

Section 14.4 Amendments or Modifications. No amendments or modifications of the terms and provisions of this Agreement shall be effective except by the execution of a supplementary written agreement executed by Algonquin and Islander East.

Section 14.5 Relationship between the Parties. Nothing in this Agreement or any related agreement shall be deemed to constitute a partnership or joint venture between the Parties or to constitute one Party as the agent of the other for any purpose.

Section 14.6 Notices. Unless otherwise specifically provided in this Agreement, any written notice or other communication shall be deemed given and received on the date on which such notice or communication is given by facsimile, and confirmed as received by the other Party, or the date received if given by registered or certified mail, postage prepaid, addressed:

A. if to ALGONQUIN:

1284 Soldiers Field Road
Boston, MA 02135

or such other address as may be designated from time to time by written notice to Islander East.

B. if to ISLANDER EAST:

P.O. Box 1642
Houston, TX 77251-1642

or at such other address as may be designated from time to time by written notice to Algonquin.

Section 14.7 Headings. The headings contained in this Agreement are for reference purposes only and shall not affect the meaning or interpretation of this Agreement.

Section 14.8 Assignment. Any company which succeeds by purchase, merger, or consolidation of title to the properties, substantially as an entirety, of Algonquin or Islander East, will be entitled to the rights and will be subject to the obligations of its predecessor in title under this Lease Agreement. Otherwise, except with respect to Section 14.8(b), or in the case of an assignment by either party to an affiliate that meets the creditworthiness provisions in Section 14.9, neither Algonquin nor Islander East may assign any of its rights or obligations under this Lease Agreement without the prior written consent of the other Party hereto.

(a) Islander East acknowledges and agrees that Algonquin shall have the right to assign, mortgage, or pledge all or any of its rights, interests, and benefits under this Lease Agreement to secure payment of any indebtedness incurred or to be incurred in connection with the development and construction of the Project Facilities.

Section 14.9 Creditworthiness. Islander East commits that, within thirty (30) days following the date of FERC certificate issuance to Algonquin, Islander East shall provide

information that demonstrates that Islander East, or any entity that guarantees Islander East's obligations under the Lease Agreement, has a credit rating or financial position satisfactory to Algonquin in its sole discretion reasonably exercised. In the event that Islander East fails to satisfy these creditworthiness requirements contemplated by this Section 14.9 (by the deadline contemplated herein), Algonquin shall have the right to immediately terminate this Lease Agreement with written notice to Islander East.

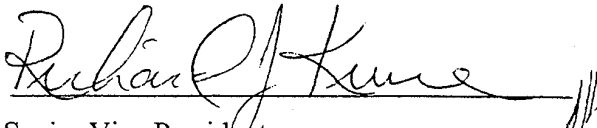
Section 14.10 Third Party Beneficiaries. This Agreement is made and entered into for the sole benefit of the Parties, and their permitted successors and assigns, and no other Person shall be a direct or indirect legal beneficiary of, have any rights under or have any direct or indirect cause of action or claim in connection with this Agreement.

Section 14.11 Severability. If, at any time, any provision of this Agreement is or becomes illegal, invalid or unenforceable in any respect under the law of any jurisdiction, neither the legality, validity or enforceability of the remaining provisions hereof nor the legality, validity or enforceability of such provision under the law of any other jurisdiction shall in any way be affected or impaired thereby and the Parties shall promptly negotiate to restore this Agreement as near as possible to its original intent and economic effect.

Section 14.12 Counterparts. This Agreement may be executed in several counterparts, each of which is an original and all of which constitutes one and the same instrument.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their respective duly authorized officers, the day and year first above written.



ALGONQUIN GAS TRANSMISSION COMPANY

By: 
Title: Senior Vice President

ATTEST:



DUKE ENERGY ISLANDER EAST PIPELINE
COMPANY, L.L.C. AS OPERATOR OF
ISLANDER EAST PIPELINE COMPANY, L.L.C.

By:  
Title: Senior Vice President

ATTEST:



ISLANDER EAST PIPELINE COMPANY, L.L.C.

EXHIBIT I -1

MARKET DATA – MARKET STUDY

Islander East Market Study

Merrimack Energy
June 2001

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Executive Summary

The Islander East Pipeline, LLC is a natural gas pipeline project jointly developed by Duke Energy and KeySpan Corporation to primarily serve the growing markets of Long Island, New York City and Connecticut (i.e. target markets). The project is initially designed to provide 285,000 dekatherms (dth) per day of new, incremental gas pipeline capacity directly to the target markets beginning on November 1, 2003. The project originates from the Algonquin Gas Transmission Company's (Algonquin) pipeline system in central Connecticut, and then traverses the Long Island Sound to a landing point at Wading River, Long Island, and on to Brookhaven where it connects into the KeySpan system. The markets targeted by Islander East have been among the fastest growing gas markets in the country and have historically experienced pipeline capacity constraints. The Islander East project will provide access to numerous gas supply basins throughout the North American pipeline system, including domestic US supplies, western Canadian supplies and most importantly, east coast Canadian supplies, through Algonquin's proposed interconnection with Maritimes & Northeast Pipeline (M&NE) via the proposed HubLine project.

The Project Sponsors retained Merrimack Energy to undertake an assessment of the demand for natural gas in the markets targeted by the project as well as the associated economic impacts/benefits of the project. Merrimack Energy has relied upon a bottom-up approach as a starting point for the assessment. This approach includes combining forecasts of sales and throughput for the LDCs in the target market as well as for existing and new gas-fired power generators. Gas requirements in the electric power market are based on projected plant dispatch levels.

Gas requirements in the New York City, Long Island and Connecticut have increased rapidly due largely to the additions in pipeline capacity since the late 1980's. Gas demand in New York increased at an average annual rate of 3.9% per year during the 1990's, with growth in the target markets increasing at a rate of 4.7%. Gas requirements in Connecticut increased at a similar rate, led by increases in demand in commercial and industrial sectors.

Demand for natural gas in the power markets in New York City and Long Island is expected to increase dramatically. This is due to the current shortage of generating capacity in these markets, transmission capacity constraints into the downstate region, the requirements of the NYISO that the majority of generation has to be located within the market in both New York City and Long Island, and the recent rejection by the Connecticut Siting Council of a 300 MW cable project from Connecticut to Long Island. As a result, more generating capacity will be needed in the target markets, all of which are expected to be gas-fired. The amount of electric generation capacity required for Long Island by 2005 ranges from 386 MW to 1,800 MW, requiring 62,000 dth per day to 288,000 dth per day of pipeline capacity. New York City is expected to need at least 865 MW by 2005 and over 3,000 MW by 2010. This would require at least 138,000 dth per day of pipeline capacity by 2005 and at least 487,000 dth per day by 2010.

Connecticut is part of the ISO New England, which manages the region's bulk power generation and transmission system. There are a number of power projects proposed in Connecticut, including over 2,000 MW by NRG at existing sites of generating units acquired from Connecticut Light and Power in southern Connecticut. Several of these plants are subject to recently approved legislation in Connecticut to reduce emissions in six of the oldest plants in Connecticut. It is likely that a portion of this capacity will be converted to gas or repowered to a more efficient combined cycle configuration during the forecast period.

The results of the forecast illustrate the significant market growth expected in the target market. Annual gas requirements are projected to increase by approximately 257 Bcf over the forecast period. This equates to an average annual growth rate of 2.67% per year between 2001 and 2010. The projections of peak day requirements illustrate that estimated market demand is more than adequate to support the pipeline capacity proposed by the Islander East Pipeline. Peak day requirements are projected to increase by 648,000 dth per day between 2001 and 2005 and by 422,000 dth per day between 2005 and 2010. Analysis of the demand/supply balance of LDC resources in the target markets illustrates that New York utilities (or those supplying their customers) will require substantial amounts of pipeline capacity to meet winter season requirements. KeySpan, Consolidated Edison, and the Connecticut LDCs will require 450,000 dth per day of capacity by 2010.

The analysis shows that the requirements for new incremental gas supplies and pipeline capacity on an annual, seasonal, and peak day basis is adequate to support the amount of capacity provided by the Islander East Pipeline, illustrating a definite need for the project in the near term. Also, the potential expandability of the project to 500,000 dth per day allows the opportunity for system expansion in conjunction with load growth.

In addition to providing incremental pipeline capacity to a growing market, Islander East provides a number of other benefits to gas customers in the target markets. First, Islander East enhances reliability by adding a separate pipeline onto Long Island. Second, the project leads to higher levels of deliverability in Connecticut and southeastern New York markets. Third, the project will further diversify the supply portfolio of the customers in the target market by allowing increased access to Sable Island gas through the backfeed of the Algonquin system. Fourth, Islander East will deliver high pressure gas to those areas which need higher pressures to support electric generation, such as the New Haven area. Fifth, the project will allow greater access to Sable gas which should serve to enhance price competition. Lastly, the backfeed of the Algonquin system from HubLine and Islander East will serve to minimize construction costs of expansions on the system.

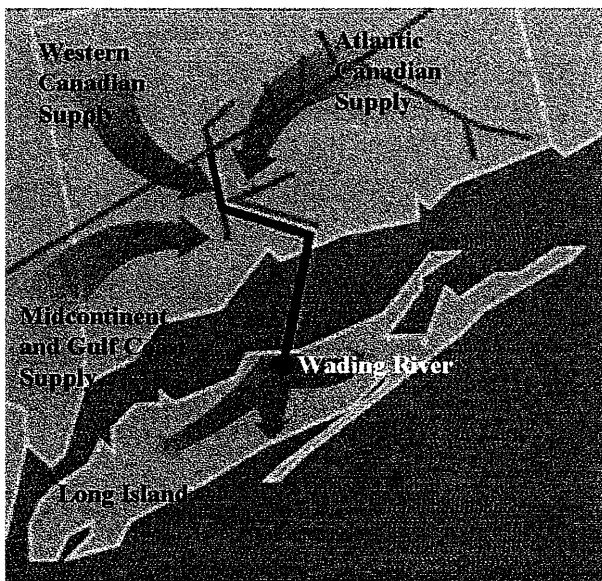
I. Introduction

I.1. Project Description

The Islander East Pipeline, LLC is a natural gas pipeline project jointly developed by Duke Energy and KeySpan Corporation to primarily serve Long Island, New York City and Connecticut markets (i.e. target markets). The project is initially designed to provide 285,000 dekatherms (dth) per day of new, incremental gas pipeline capacity directly to Connecticut, Long Island and New York City markets beginning on November 1, 2003.

As illustrated in Exhibit I-1, the project originates from the Algonquin system in central Connecticut, and then traverses the Long Island Sound to a landing point at Wading River, Long Island, and on to Brookhaven, where it connects into the KeySpan system. In addition to the direct benefit to the southeastern New York market, construction of the project in combination with the HubLine project will provide enhanced capabilities for the Algonquin system to meet growth in gas demand in central and southern Connecticut markets as well.

Exhibit I-1 Islander East Project Map



The initial project facilities consist of approximately 10.1 miles of 24-inch pipeline on-shore in Connecticut, 22.8 miles of 24-inch pipeline offshore across Long Island Sound, and 17.5 miles of 24-inch pipeline on-shore on Long Island (to Brookhaven, Calverton, and other points).

Long Island and New York City have historically been relatively isolated markets from both a gas and an electric perspective. On the gas side, pipeline capacity limitations into New York City from the west and limitations in the New York Facilities System have been cited as limits to growth in gas requirements. Recognition of these capacity limitations has spurred several pipeline project

proposals from the Midwest, which are targeting the New York City market. In the electric power market, transmission limitations into the southeast region of the state and limited generation capacity in these markets, requires new infrastructure development to meet growing demand and maintain electric system reliability. If not addressed, limitations in both electric and natural gas infrastructure could place a limit on growth, jeopardize system reliability, and lead to higher energy costs in these markets. Thus, the rapidly growing gas and electric markets in these regions illustrates the need to expand the infrastructure in this market. The Islander East Pipeline project provides the infrastructure needed to enable gas market growth, as well as provide the means of

expanding electric generation in these markets. Islander East also has the potential to expand from 285,000 dth per day to 500,000 dth per day to meet market demands.

In Connecticut, the project enhances the capability of the Algonquin system to provide high-pressure gas to power generation facilities and increased deliverability to allow for increased penetration of gas into new and existing markets. Access to gas supplies allows for increased fuel competition and the option or opportunity to displace higher emission fuels in existing facilities.

This project provides the type of gas infrastructure development that the rapidly growing Long Island, New York City, and Connecticut markets require. The project provides a competitive pipeline alternative with a number of reliability and flexibility benefits to customers in these markets. The added flexibility of the pipeline system onto Long Island provides operational benefits for the entire southeast New York market, by avoiding the existing bottlenecks of the local distribution network of the New York Facilities System, which currently receives roughly 60% of its gas supply on the western edge of their service territory. The project provides another pipeline option for Long Island, adding a third separate underwater line in addition to the Transco and Iroquois facilities. This allows for deliveries into Long Island from the east and now from the north, thus enhancing gas supply reliability. Islander East also provides access to numerous supply basins throughout the North American pipeline system, including domestic US supplies, western Canadian supplies and most importantly, east coast Canadian supplies, through Algonquin's proposed interconnection with M&NE (via HubLine) for all target markets.

The Islander East project is designed to provide direct pipeline service to one of the fastest growing gas markets in the country and serves to enhance supply access and reliability for the central and southern Connecticut gas system. Growth rates for gas in the Long Island and New York City markets have greatly exceeded the national average for the past several years. Much of this demand is the result of growth in the residential load on eastern Long Island. This load growth on Long Island is expected to continue at approximately 6% per year through 2003, due primarily to homeowner conversions to natural gas. In addition to projected growth in traditional local distribution company (LDC) markets, this project is designed to deliver high pressure gas to new power generation facilities expected to be constructed on Long Island, in New York City, and in southern Connecticut to meet the rapidly growing electric requirements.

Thus, by interconnecting with KeySpan's distribution network on the eastern end of Long Island, Islander East can serve the growing demand of Long Island, directly feed proposed power generation loads in the target markets and, through displacement opportunities, access New York City markets, eliminating costly distribution facility upgrades, and providing cost-effective supply diversity, flexibility and security of supply.

1.2. The Project's Role in New York and Connecticut Energy Markets

The project is designed to meet several important objectives. First, the project will deliver significant quantities of high-pressure gas to rapidly growing gas markets in a region historically constrained by inadequate pipeline capacity. Second, the addition of pipeline capacity from this project will provide access to gas supplies from all the major supply basins in North America, including the newly developed resources from off-shore Nova Scotia. Third, the completion of this project, in conjunction with other recently proposed projects in the Northeast (including M&NE Phase III Project and HubLine), will expand customers' fuel supply options, not only among competing natural gas suppliers, but also between gas and oil. This will increase fuel supply competition and facilitate competition in the region's newly restructured power market. Fourth, the project will provide significant operating flexibility to both the Connecticut and New York markets, with improved deliverability and higher pressure gas. Fifth, the project will provide enhanced reliability to a region that has traditionally faced pipeline capacity constraints, by adding new pipeline capacity infrastructure and increased deliverability to the entire Northeast market.

1.3. The Purpose of This Report

The purpose of this assessment is to provide a detailed market analysis of both gas and electric markets in the regions targeted by the Islander East Pipeline Project (i.e. Long Island, New York City and central and southern Connecticut). This project reflects the shifts in the Northeast market toward greater reliance upon natural gas and an integration of the Northeast gas market. These shifts have been prompted by various economic, technological, resource, environmental, and regulatory changes in the regional economy over the recent period. This analysis focuses on two of these factors in particular: the evolving natural gas infrastructure in the Northeast, and the growing demand for gas in these markets.

This analysis involves an assessment of the projected requirements for natural gas in the Long Island, New York City, and central and southern Connecticut markets over the next 10-15 years, in markets accessible to the project. The projections combine both the expected growth in traditional LDC market segments, as well as the projected power market demand based on the need for new electric generating capacity. The intent of this analysis is to determine whether a viable market exists for the project, along with a qualitative and quantitative assessment of the benefits of the project in this gas market.

1.4. Methodology

Merrimack Energy has relied upon a bottom-up approach as a starting point for the evaluation. This approach combines both traditional LDC market segments and electric power generation markets. This analysis includes a compilation of forecasts of sales or sendout and transportation by sector for individual LDCs in the market. For the electric power market, the forecast is based on projected gas requirements for each new and

existing gas capable unit in the Long Island and New York City market, based on projected operations of existing units and projections for new entrant merchant plants in the target market. Gas requirements in these units are based on projected plant dispatch and are calculated as the product of projected plant generation and the plant heat rate. The analysis calculates requirements on a daily basis and develops a load profile to determine how the project will be expected to operate.

1.5. Report Organization

This report is organized into six other sections besides the Introduction. Section II provides a historical overview of the gas markets in New York overall and southeastern New York in particular, principally in the New York City and Long Island areas, as well as the Connecticut gas market. These markets have been identified as the primary target markets for the Island East Pipeline. The overview of these markets will provide a perspective on recent trends in gas requirements in these markets and the factors driving such demand.

Section III describes the results of our forecast of gas requirements in traditional LDC market segments (i.e. residential, commercial and industrial) for each of the major LDCs in the primary target market area in New York and Connecticut. The forecast is based on the projections prepared by each of the LDCs, adjusted for any known changes in requirements. LDC forecasts of demand are combined with supply information to determine peak day, winter season, and annual gas requirements. Analysis of winter season requirements, in conjunction with existing gas supply and transportation contracts, can determine the amount of annual, seasonal or peaking service required by the LDCs to meet customer requirements.

Section IV presents an assessment of the electric power markets on Long Island and New York City and includes our forecast of gas requirements in power generation facilities (both existing and new merchant generation) in these markets. The forecast of gas requirements in these facilities is a derived demand, based on the projected dispatch of each unit in the New York City and Long Island markets. The forecast results are calculated on a daily and annual basis. Section V provides an assessment of the power market in Connecticut, as a sub-region within the overall New England market. Section VI combines the forecast of gas requirements in LDC and power markets in New York and Connecticut to arrive at a total potential market based on peak day, seasonal and annual requirements generated for each market. The final section describes the other economic benefits of the project given its accessibility to multiple supply areas and the supply reliability and flexibility benefits provided to the Northeast gas market.

II. Overview of the New York and Connecticut Gas Markets

As indicated, the primary target markets for the project in southeastern New York and central and southern Connecticut are the LDC and power markets, which have been experiencing rapid growth in gas demand, and face the need for additional infrastructure to continue such growth. As a result, this section will provide a historical perspective on the demand for natural gas in the overall New York and Connecticut markets, as well as the market in southeastern New York, and describe the factors that have contributed to such growth. Recent trends in these markets and the changing role of natural gas in meeting total energy requirements will also be reviewed. In addition, there will be a focus on the overall increase in natural gas requirements in the target markets over the 1990-1999 timeframe, the sectors contributing to the increase, the role of gas in end-use markets and the saturation of natural gas in retail markets. A review of recent gas requirements trends will shed light on the future potential for gas in both the New York and Connecticut markets.

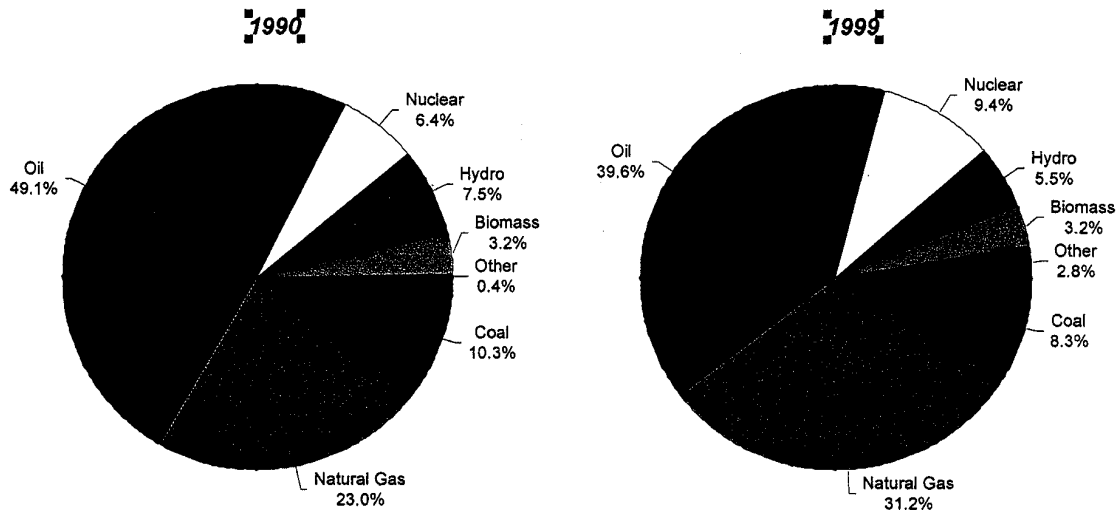
II.1. New York Natural Gas Market

II.1.a. Primary Energy Requirements

Throughout the 1990s, the energy mix in New York has been changing. During this time, natural gas has been playing an increasingly important role in meeting the state's primary energy needs. In fact, New York has been one of the fastest growing natural gas markets in the US, due to the historically low penetration of gas in specific downstate markets and the lack of sufficient pipeline infrastructure into key growth areas in the state. Not surprisingly, the rapid increase in gas utilization has corresponded to the increases in pipeline capacity into the state since the late 1980s.

Exhibit II-1 shows the changing role of the various primary fuels in the New York market. While overall energy use increased at an average annual rate of 0.5% per year between 1990-1999, overall natural gas use increased at a much higher rate. In 1990, natural gas accounted for 23.0% of total primary energy consumption in New York, but by 1999, its share reached 31.2%. Natural gas has been largely displacing oil in industrial and utility applications, accounting for the increase in demand. Not only has gas displaced oil in several markets, but gas is obviously the fuel of choice in incremental markets, serving to meet the growth in energy requirements while other fuels either remain flat or decline.

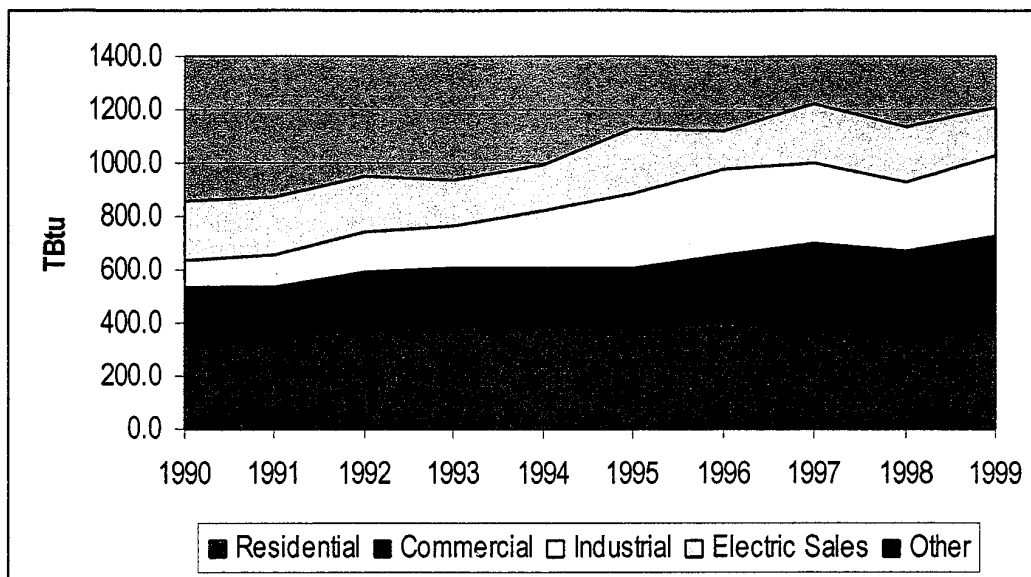
Exhibit II-1 Primary Energy Consumption - New York



II.1.b. Gas Consumption/Requirements

As illustrated in Exhibit II-2, natural gas deliveries in New York overall have increased from 857.5 TBtu in 1990 to 1,209.6 TBtu by 1999. Over this timeframe, gas use has therefore increased by 352.1 TBtu, at a rate of growth of 3.9% per year in New York State. While residential demand has been fairly flat, (based on weather) commercial and industrial sectors have experienced sustained increases in demand. In particular, sales of gas to cogeneration and non-utility customers are largely reflected in the industrial and commercial sectors, which have experienced a rapid increase in gas use, largely beginning in the 1993-1994 timeframe. Electric utility gas consumption has fluctuated from year to year due to the competition between oil and gas for power generation requirements in dual-fuel electric utility units. Most of the gas use in the electric utility sector is on an interruptible basis, subject to competition with residual oil.

Exhibit II-2 New York Gas Requirements



The increased reliance on natural gas as the fuel of choice to meet increases in energy requirements is not anticipated to abate in the near term, since requirements for gas are being driven by several factors. These include:

1. A strong regional economy.
2. New and more stringent environmental regulations.
3. Regulatory reforms designed to introduce competition in gas and electric markets.
4. Investment plans for electric generating capacity and planned use of gas by industrial/commercial projects.
5. The development of significant gas reserves in nearby eastern Canada.
6. Proposed additions to natural gas supply and deliverability capability targeted for the New York market.

II.1.c. Electric Utility Fuel Mix

The fuel mix in the electric utility market in New York is fairly well balanced. In 1998, utility generating units produced 80% of the power generated in the state, while non-utility generation accounted for nearly 20%.

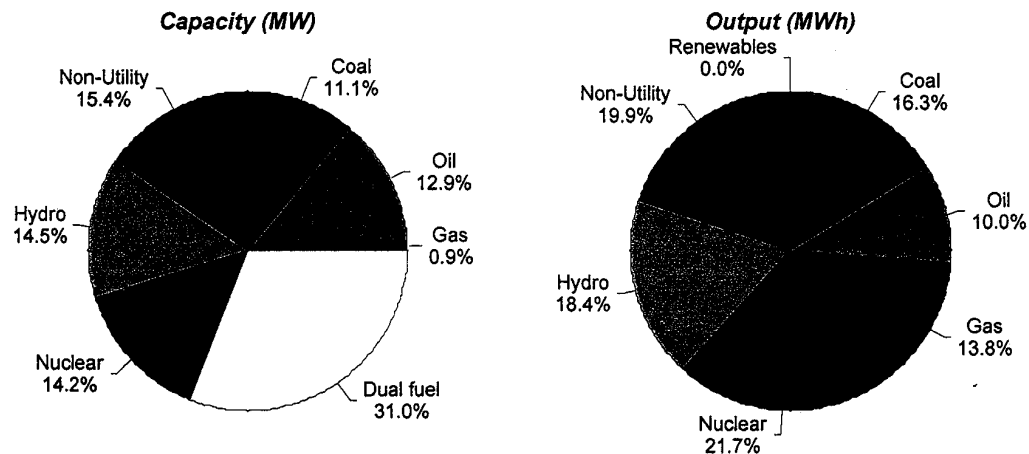
Exhibit II-3 illustrates the generating capacity and output by generation source in New York. It is important to note that dual-fuel generation (oil and gas) accounted for over

30% of all installed generation capacity in New York, illustrating the importance of competition between gas and oil in the power market. While traditional baseload generation from nuclear, coal, and hydro combine for approximately 40% of installed generating capacity, these three sources of generation produced over 56% of the electric output in the state in 1998.

The significant growth in gas demand illustrated in the industrial market is largely a reflection of increased gas use in non-utility cogeneration projects. These projects were encouraged by both federal and state regulations focused on initiating competition for traditional generation sources. The vast majority of these facilities use gas as their primary fuel source.

The fuel mix in New York, therefore, changes considerably if the fuels used to generate power in non-utility units are appropriately accounted for. For example, approximately 80% of the over 5,000 MW of non-utility generating capacity is gas-fired generation. If the amount of gas used in non-utility generation units is included in the overall power generation fuel mix, the role of gas in the power market would increase dramatically.

Exhibit II-3 New York Generating Capacity and Output by Fuel Type-1998



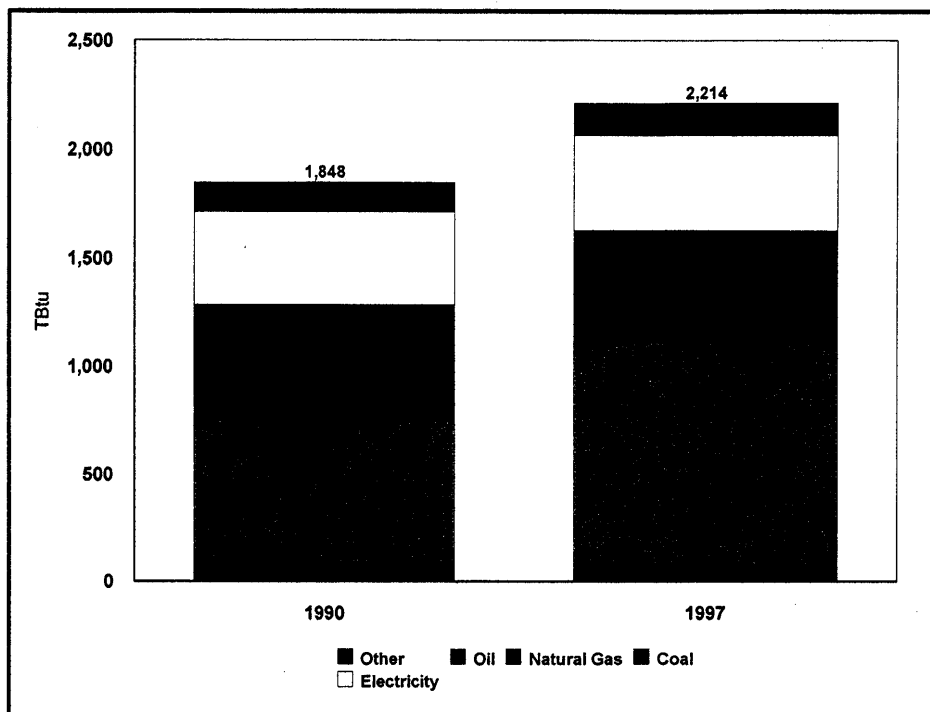
For example, the inclusion of gas use in the non-utility market increases the use of gas in the power market to approximately 25% of total fuel requirements, resulting in natural gas being the dominant singular fuel in the New York power market.

II.1.d. End-Use Market Fuel Requirements

In end-use markets (defined as residential, commercial, and industrial), the share of natural gas has increased from 35.4% in 1990 to 46.5% by 1997. As illustrated in Exhibit II-4, the market share for all other energy sources has decreased on a relative basis. Gas has clearly displaced oil and coal in end-use markets and now enjoys a

predominant position in residential, commercial and industrial markets. While total energy requirements in end-use sectors increased at an average annual rate of 2.6% between 1990-1997, natural gas use increased at an average annual rate of 6.7%.

Exhibit II-4 End-Use Consumption by Fuel Type – 1990 and 1997



II.1.e. Saturation and Penetration of Natural Gas

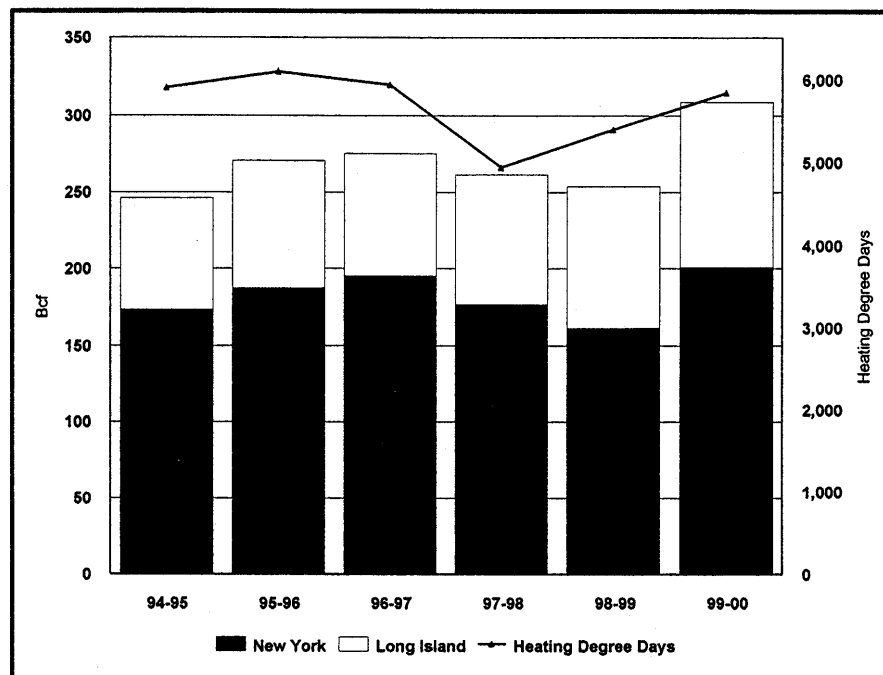
Although natural gas has increased its market share in the New York energy market since 1990, saturation of natural gas in the residential heating market still lags behind the national average. According to the American Gas Association, there are nearly 4.0 million residential gas customers in New York, while only 2.8 million use gas for heating purposes. Therefore, in New York, 70% of the households that have gas service also heat with gas. In comparison, for the US overall, this saturation level is approximately 86%. In New York, therefore, over 1.2 million residential customers who have gas service chose to heat with another fuel, representing a potentially large market for expanded gas use.

Within New York there is also a significant difference in saturation between regions. In New York City, the large majority of gas customers who have service also heat with gas. On Long Island, many areas do not have gas service and a number of customers who have gas service do not currently heat with gas.

II.1.f. Gas Use in the Southeastern New York Market

On a regional market level, an analysis of KeySpan's throughput data over the 94/95 gas year to the 99/00 gas year (November to October) illustrates significant growth in both the Long Island and New York City markets. The throughput for both systems in total has increased at an average annual rate of 4.7% over this recent historical timeframe. Growth in the KeySpan Long Island service area has averaged 8% per year over the same time period, while growth in the KeySpan New York service area has averaged 3.13%. Exhibit II-5 provides historical data on gas sales for each of KeySpan's divisions in Southeastern New York over the past six years. A complete listing of the back-up data is included in Appendix A.

Exhibit II-5 KeySpan System Throughput – New York and Long Island



For the KeySpan system overall, throughput increased by nearly 65 Bcf over the past few years, while peak day sendout increased by nearly 100,000 dth/day over the same time frame, illustrating the high historical growth levels in New York City and Long Island markets. At the same time, the amount of incremental pipeline capacity has not kept pace with this demand growth and has led to a need for additional gas infrastructure to facilitate market expansion.

A major change on the KeySpan system during the 94/95 to 99/00 time period was the dramatic shift from gas sales by the LDC to transportation only service. For KeySpan, this trend has been much more pronounced in New York City, where transportation volumes represented approximately 34% of total throughput in 1999/2000. By contrast, for KeySpan Long Island, transportation volumes represented only 8.5% of total

throughput. Sales by the LDC to end-use customers still predominate on the Long Island system and the utility maintains a major merchant function on the Island.

II.1.g. Natural Gas Delivery Infrastructure

Natural gas requirements in the New York market (and other regions in the Northeast) are met through several supply/transportation alternatives. The major supply alternatives include long-haul transportation of U.S. domestic supplies from the Gulf of Mexico, mid-continent supply basins and Western Canadian gas imported through Niagara Falls and Waddington, New York. Besides pipeline supplies, the market is also served via redeliveries of gas withdrawn from underground storage facilities located in the northern Appalachian areas of western Pennsylvania and western New York. Supplemental supplies such as propane-air and liquefied natural gas (LNG) are relied upon during peak periods.

The traditional long-haul transporters of domestic gas to the New York market include Transcontinental Gas Pipe Line Corporation (Transco), Texas Eastern Transmission/Duke (Texas Eastern), and Tennessee Gas Pipeline Company (Tennessee). Some gas is also delivered to Consolidated Edison off of Algonquin. These pipelines own or lease underground storage facilities in the Gulf Coast supply area and in the market area (western Pennsylvania) that are used to meet winter season requirements. The long-haul pipelines are generally designed to transport average annual daily requirements from the production areas to the storage fields, and to transport peak-day volumes from the storage fields to the major market areas in the Northeast.

In New York, these pipeline systems primarily serve the downstate market, including the target markets identified in this study. The primary access point to the target markets in New York is through the New York Facilities System from the west. Gas is delivered into the New York Facilities System and is fed to the three LDCs in the target market, KeySpan New York, KeySpan Long Island and Consolidated Edison, through this system.

Several regional pipelines, located primarily in the northern Appalachian area, provide additional underground storage services to the long-haul pipelines and serve LDC customers in the upstate New York market. These include Columbia Gas Transmission Corporation (Columbia), Consolidated Gas Transmission Company (Consolidated), and National Fuel Gas Supply Corporation (National Fuel). All of these pipelines directly serve New York.

In addition, two other pipelines serve New York State with gas supplies imported from Canada. One of these is the Empire Pipeline (Empire), an intrastate line that transports gas from the Niagara Falls area along the southern shore of Lake Ontario to markets in Rochester and in the proximity of Syracuse, New York. The other is the Iroquois Gas Transmission System (Iroquois), an interstate pipeline serving both New York and

New England. Iroquois receives gas off of the TransCanada system at Waddington, New York at the Canadian border. It delivers gas to interconnecting pipelines such as Consolidated, Tennessee, Algonquin, as well as to markets in eastern New York State, Connecticut, and Long Island after crossing Long Island Sound.

On a local level, gas supply to Long Island is provided via an underwater line at Long Beach, through the Iroquois System, and through the New York Facilities System. Outages on any of these systems could create significant reliability problems for the Long Island market.

II.2. Connecticut Natural Gas Market

The state of Connecticut will also greatly benefit from this project. Islander East is part of a pipeline system that will improve access to natural gas from offshore Nova Scotia. Gas from the Sable basin will provide Connecticut with supply basin diversity and will help to protect the state from supply and pipeline interruptions. In addition, the Islander East Pipeline allows for future pipeline infrastructure capability in the Connecticut market to meet growth in state energy requirements and enhance fuel competition.

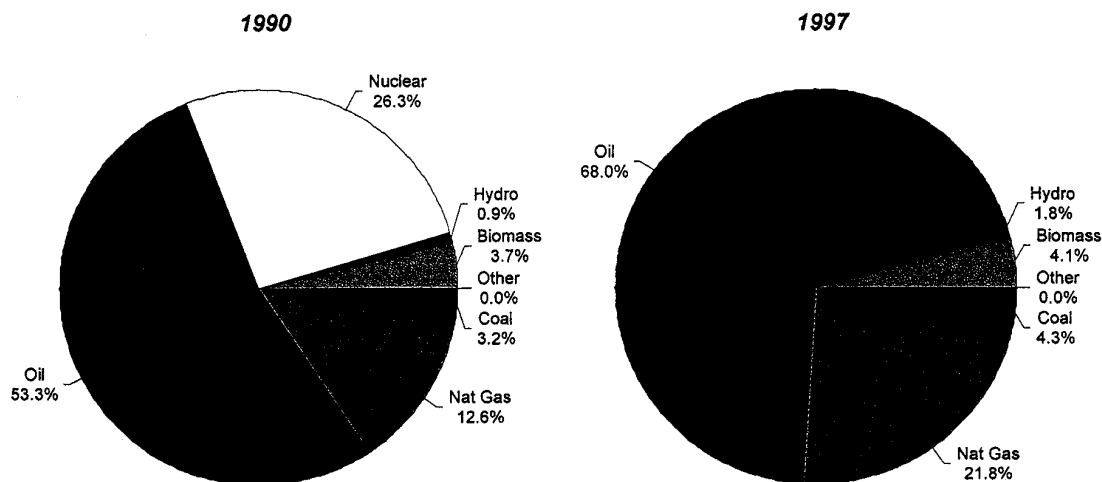
This section will present a historical perspective on natural gas demand in the Connecticut market over the 1990-1997 timeframe. Like other regions, demand for gas in Connecticut is growing and much of that growth is in the power generation sector. A look at the changing fuel mix in Connecticut and the trend towards increasing use of natural gas in the future will also be examined.

II.2.a. Primary Energy Requirement

Throughout the 1990s, the energy mix in Connecticut and the whole Northeast has been changing. One of the major changes in the Connecticut energy market has been the decreased reliance on nuclear power. In 1990, the nuclear sector supplied 26% of the state's primary energy. At that time, Connecticut had 3,217 MW of capability from four nuclear power units: Connecticut Yankee and Millstone units 1, 2, & 3. By 1997, the Connecticut Yankee and Millstone 1 units were permanently closed, reducing the state's nuclear capability to 2,011 MW.

Exhibit II-6 illustrates the changing role of the various primary fuels in the Connecticut market. Between 1996 and 1998, the Millstone 2 & 3 units were temporarily shut down for various safety reasons and consequently nuclear power was reduced to an insignificant role in the Connecticut energy mix. However, in 1999 the Millstone units 2 & 3 were again operating and nuclear power again took on an important role in the energy mix. For example, in the year 2000, Millstone 2 (873 net MW) had an average capacity factor of 81.6% and Millstone 3 (1,155 net MW) had an average capacity factor of 99.63%.

Exhibit II-6 Primary Energy Consumption - Connecticut

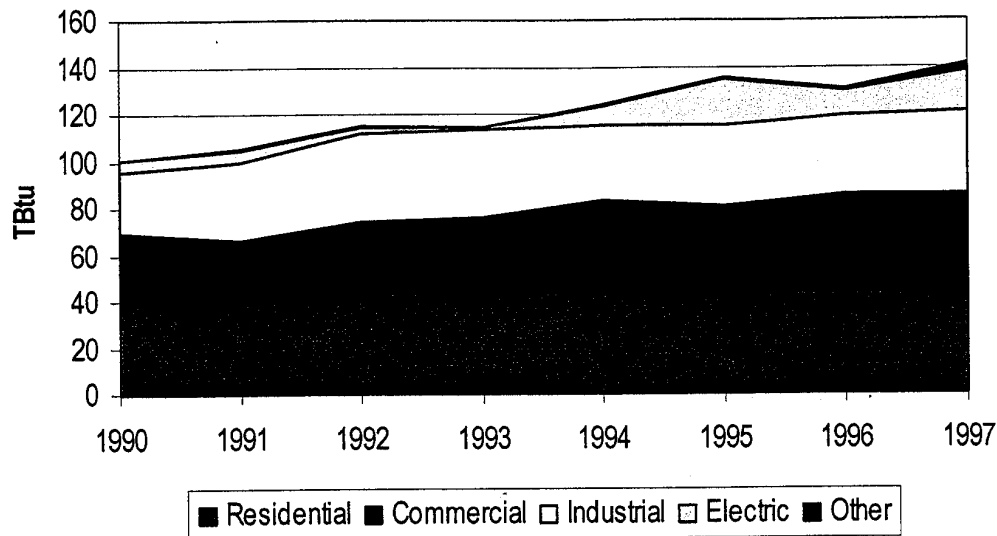


On an interim basis, the reduction in energy use from nuclear sources was made up by an increase in the use of oil and natural gas. In 1990, natural gas accounted for 13% of total primary energy consumption. By 1997, gas made up 22% of the primary energy market in Connecticut. While overall energy use increased at an average annual rate of 0.6% per year between 1990-1997, overall natural gas use increased at a much higher rate. The increase in natural gas demand has been most significant in industrial and utility applications, where gas has been displacing oil. Between 1990-1997, gas consumption grew by 39.7%, whereas oil consumption increased by only 2.6%. Natural gas has been the fuel of choice in incremental markets and has served to meet a major component of the growth in Connecticut's energy requirements.

II.2.b. Gas Consumption/Requirements

As illustrated in Exhibit II-7, natural gas deliveries in Connecticut overall have increased from 100.9 TBtu in 1990 to 140.7 TBtu by 1997. Over this timeframe, gas use increased by 39.8 TBtu or 4.9% per year. While residential demand has been fairly flat, (based on weather), commercial and industrial sectors have experienced sustained increases in demand. Gas consumption by electric utilities increased the fastest over the time period, but total gas consumption in this sector is less than one half of that consumed in each of the three end-use sectors. The reason gas penetration in the power generation is less than in the end-use sectors is that gas faces major competition from alternative fuels in power generation. Today, oil-fired and nuclear powered units dominate the Connecticut electricity portfolio, with minor competition coming from coal. Many electric utility units have dual-fuel capability, so gas is used mainly on an interruptible basis in this sector, based on competition with residual oil.

Exhibit II-7 Connecticut Gas Requirements



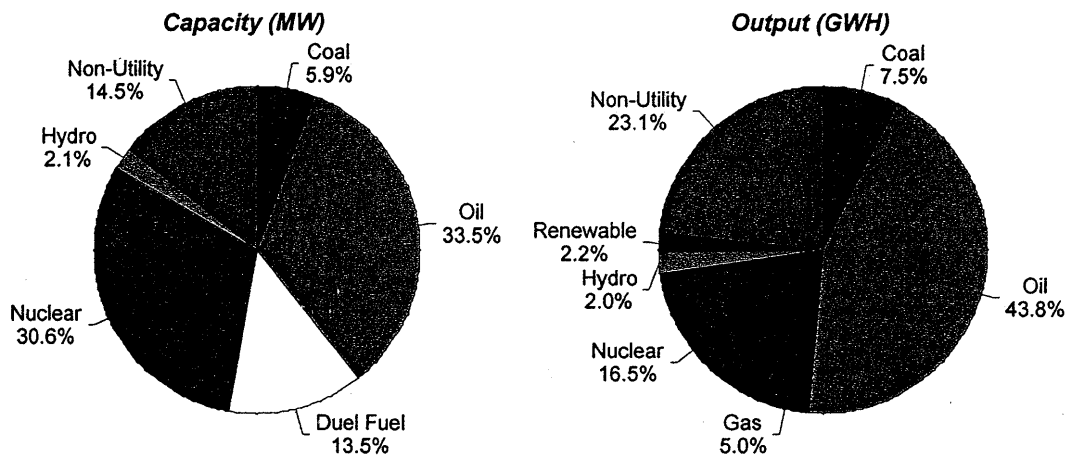
II.2.c. Electric Utility Fuel Mix

The fuel mix in the electric utility market in Connecticut has changed dramatically in the past decade. In 1998 (the last year in which complete state level data on all sectors is available), utility-generating units produced 77% of the power generated in the state, while non-utility generation accounted for nearly 23%.

Exhibit II-8 illustrates the generating capacity and output by generation source in Connecticut. It is important to note that dual-fuel generation (oil and gas) accounted for over 13.5% of all installed generation capacity in Connecticut, illustrating that the competition between gas and oil in the power market is present, but not as critical as it is in New York. A distorting factor that year was nuclear generation units made up 30.6% of the capability and only 16.5% of the output due to plant shut downs.

With much of Connecticut's nuclear capacity being shut down in 1997, the majority of its power generation came from oil and coal (66.8% combined). Connecticut is a prime region for conversions and re-powering projects. Converting some of the existing oil and coal plants to gas is environmentally preferred. The expectation is that new gas-fired units will serve projected incremental growth in power demand in the New England Power Pool (NEPOOL) region.

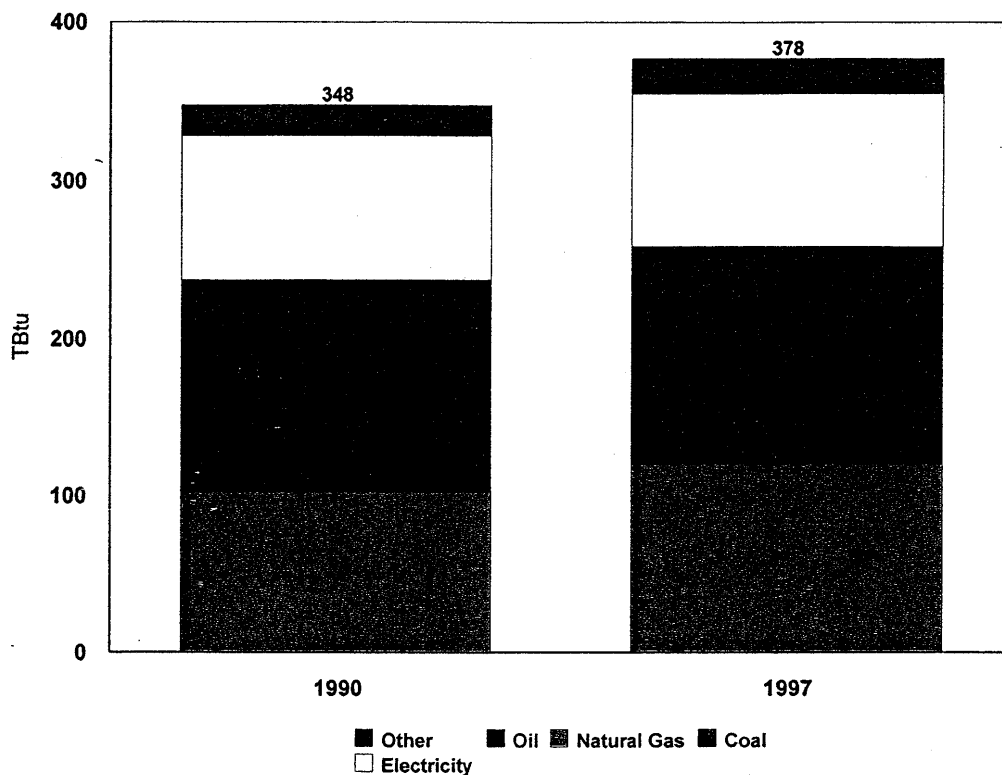
Exhibit II-8 Connecticut Generating Capacity & Output by Fuel Type - 1998



II.2.d. End-Use Market Fuel Requirements

In end-use markets (defined as residential, commercial, and industrial), the share of natural gas has increased from 29.5% in 1990 to 32.0% by 1997. Oil consumption in the end-use market declined from 38.5% to 36.3%, during the same time frame. Oil use was flat in the commercial sector and actually declined in the industrial sector. While total energy requirements in end-use sectors increased by 29.6 TBtu between 1990-1997, natural gas captured 18.2 TBtu (61.5%) of the increase. As illustrated in Exhibit II-9, with the exception of wood use (other) the market share for all other energy sources decreased on a relative basis. Gas growth in the end-use markets has been at the expense of oil and now has almost an equivalent share of the end-use markets.

Exhibit II-9 End-Use Consumption by Fuel Type – 1990 and 1997



II.2.e. Natural Gas Delivery Infrastructure in Connecticut

Natural gas requirements in the Connecticut market are met through several supply/transportation alternatives. Like New York, the major supply alternatives include long-haul transportation of U.S. domestic supplies from the Gulf of Mexico and mid-continent supply basins, as well as Western Canadian gas imported through Niagara Falls and Waddington. The two pipelines that supply the majority of domestic gas to New England are the Algonquin and Tennessee systems. In 2000, Connecticut also gained access to gas supplies from eastern Canada (Sable) with the construction of the M&NE Pipeline. Besides pipeline supplies, the market is also served via redeliveries of gas withdrawn from underground storage facilities located in the northern Appalachian areas of western Pennsylvania and western New York. The Connecticut market also relies on supplemental supplies such as propane-air and liquefied natural gas (LNG) during peak periods.

All of the LDCs in Connecticut make extensive use of underground storage, due to the nature of the market as primarily a seasonal heating market. The pipelines serving New England also own or lease underground storage facilities in both the supply area and the market area (western Pennsylvania). Several regional pipelines, located primarily in the northern Appalachian area, provide additional underground storage services to the

long-haul pipelines and serve LDC customers in New England. These include Columbia, Consolidated and National Fuel.

The Connecticut market is also served with gas supplies imported from western Canada. Gas from Canada reaches Connecticut via the Tennessee system, which has an interconnection at Niagara Falls, and the Iroquois system through an interconnection at Waddington, New York. Iroquois also interconnects with pipelines such as Consolidated, Tennessee, Algonquin, which enables gas from several sources to reach the Connecticut market.

Gas from eastern Canada (offshore Sable) is also entering the Connecticut market. Over 400 MMcf/d of Sable gas is currently being delivered to the Tennessee system at Dracut, Massachusetts via the M&NE Pipeline. Connecticut end-users are accessing this gas through displacement. Access to Sable supplies will in fact be enhanced with the construction of Islander East. Duke has applied to the FERC to extend the M&NE system to Beverly, MA and construct a subsea pipeline from Beverly to Fore River in Massachusetts (HubLine). HubLine would be a direct connection of M&NE to the Algonquin system. Currently, Sable gas can only reach the Algonquin system through the Tennessee system. The problems with this route are capacity restrictions at the interconnections between the Tennessee and the Algonquin systems, as well as added costs associated with incremental tolls on Tennessee.

Gas transported on HubLine is targeting markets off of the Algonquin system in southern New England, as well as markets in Connecticut and New York off of Islander East. The Islander East Project accesses markets that are large enough to provide the critical volumes necessary for the HubLine project to proceed in the short term. The ancillary benefit is that HubLine will be transporting more Sable gas than is required for Islander East and this gas will be consumed by end-users throughout New England and Connecticut.

Another benefit of the Islander East project in Connecticut is the increase in natural gas pressures in the New Haven region. New turbine technology used in today's gas-fired combined cycle power generation plants requires the pressure of the gas feeding the plant to be at least 400 psig. These new plants could be vulnerable to periodic pressure reductions. Increasing the pressure of gas deliveries in southern Connecticut improves the reliability and the options available to grass-roots power developers and re-powering projects.

III. Gas Requirements in Traditional End-Use Markets

The objective of this section of the report is to present the forecast of projected gas requirements in traditional end-use or LDC markets in southeastern New York and Connecticut. This will primarily include requirements for gas in the target markets of Long Island and New York City served by KeySpan Long Island, KeySpan New York and Consolidated Edison. Connecticut Natural Gas, Southern Connecticut Gas Company and Yankee Gas serve the LDC market in Connecticut. The analysis includes the forecast for gas demand from 2000-2010. Forecasts are provided for annual throughput (excluding electric generation), peak-day requirements, and winter season requirements, to assess the types of services and overall requirements on the part of the market participants. This forecast is then combined with the power market forecast to generate a forecast of total gas requirements in both LDC and power generation markets.

III.1. Methodology

The primary approach undertaken by Merrimack Energy to develop the above referenced forecasts of annual, winter season, and peak day sendout is to rely initially on the most recent forecasts completed by the individual LDCs in the target market and to adjust the forecast for projected sales to power generators. The individual LDC forecasts can then be aggregated to develop a regional forecast for the southeastern New York and southern Connecticut markets. Annual sales or sendout forecasts are based on normal weather conditions for each company. While LDC sales may be substituted by customer transportation, these forecasts include total throughput (sales plus transportation) and therefore represent a complete picture of gas requirements in the LDC market area.

While most forecasts present annual or peak day requirements, it is important to note that utilities do not necessarily rely on annual requirements in planning for new gas supplies. Utilities are required to have sufficient resources to meet design day as well as design year requirements. Since the important load for most LDCs in the Northeast is the heating load, design year analysis translates into a design heating season requirement. Maintaining sufficient gas supplies, transportation and storage contracts to meet the design heating season requirements is crucial for planning purposes for the LDC. Thus, Merrimack will rely on all three aspects of gas requirements analysis for purposes of developing our assessment of market need and service requirements.

Merrimack will therefore compare the LDC forecast requirements with their supply capabilities to determine the timeframe for additional supply resources, the type of resources required, and the estimated volumes of gas to meet the customer needs. While this approach does not exactly replicate the very detailed planning studies and analysis undertaken by LDCs in committing to new resource options, it does provide a reasonable perspective regarding the gas supply planning process.

III.2. Forecast of Annual, Peak Day and Winter Seasonal Gas Requirements

To develop a forecast of natural gas demand for LDC markets, the preferred option is to use the forecasts prepared by the individual gas utilities, which serve the market and adjust the forecasts to ensure consistency of results. For this analysis, Merrimack Energy has used forecasts prepared by KeySpan for their Long Island and New York City service areas as the starting point for the KeySpan market forecast. For New York State and the markets served by Consolidated Edison, we have utilized the 1998 New York Gas Group (NYGAS) Report. Since this forecast was last issued in 1998, we have applied the projected growth rate in gas demand from that forecast to the most recent historical consumption levels as the basis of the forecast for New York State. For the markets served by Consolidated Edison, the forecast year 2000/01 has been used as the starting point, and has been extrapolated utilizing the projected growth rates for KeySpan's New York City service area. Merrimack Energy has also reviewed the forecasts prepared by the US Department of Energy and the Gas Research Institute to determine if the reported forecast is consistent with these more macro oriented forecasts. It is important to note in assessing such forecasts that these forecasts do not provide individual state level or regional forecasts within a state and thus target a much broader and more diverse market.

For Connecticut, Merrimack has relied upon the recent integrated resource plans filed by the Connecticut LDCs with state regulatory agencies. The latest forecasts prepared by the LDCs were filed in late 2000, and represent a very recent assessment of the Connecticut gas market for all LDCs.

III.2.a. New York

The 1998 NYGAS forecast projected a 0.86% average annual increase in gas requirements in New York state over the 13-year period (1997/98 to 2009/2010). The NYGAS forecast estimates that gas requirements will grow by 0.74% per year between 1997-2005 and 1.10% per year from 2005 to 2010.

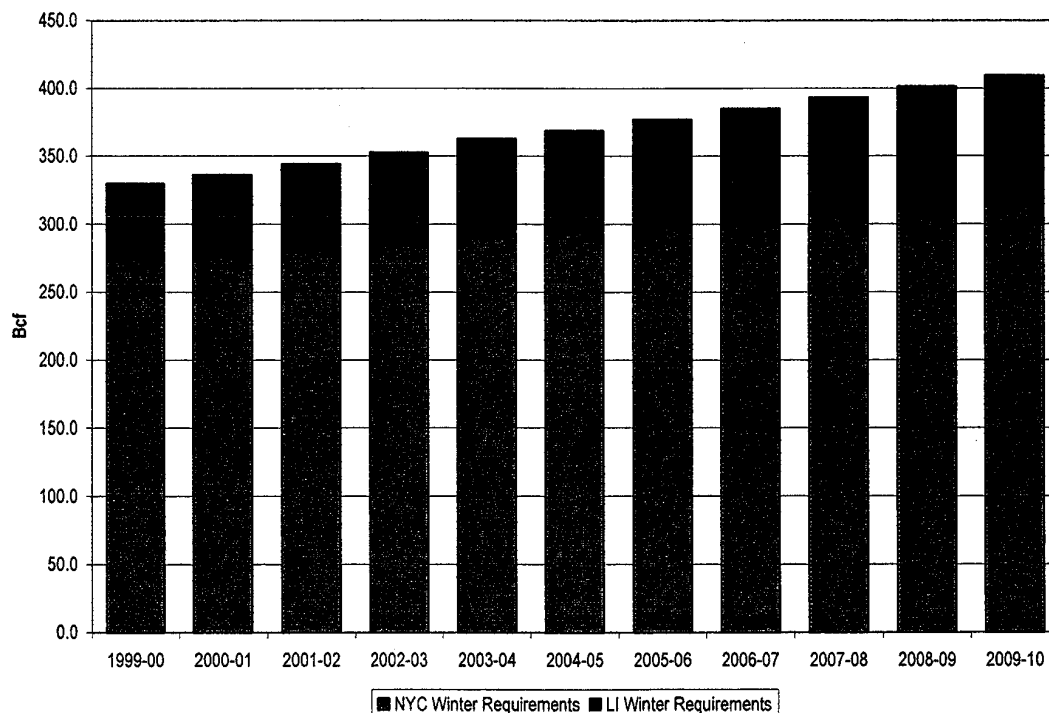
An important disparity exists with regard to the projected increase in gas requirements for the state overall and for the southeastern region in particular. For example, while the increase in gas requirements for the state overall is projected to be less than 1% per year, by contrast, the southeastern New York utilities are projected to grow at a much faster rate, consistent with historical consumption patterns. For example, gas requirements in traditional LDC markets in the service areas of the KeySpan Companies are projected to increase at an average annual rate of 3.1% per year from 1999/2000 to 2009/2010. This equates to a total increase in annual gas requirements of over 80 BCF over the forecast period. Peak demand for the KeySpan Companies is projected to increase at an average annual rate of 2.3%, increasing by 468,000 dth per day over the forecast period. Winter season requirements are projected to grow at an average annual rate of 3.05%, slightly lower than annual requirements.

For KeySpan, the increase in annual, peak and winter season demand is expected to be much higher on Long Island. Over the 10 year forecast period, average annual growth is projected to be 5.4% for Long Island, with peak demand expected to grow by 4.2% per year. This translates into an increase in peak day requirements of 350,000 dth per day over the forecast period, illustrating that the most significant growth is projected for KeySpan's Long Island system. Also, the projected growth in winter requirements for KeySpan Long Island is expected to exceed 5% per year, reflecting the significant increase in heating load projected for Long Island as a continuation of recent market activity.

Growth in Consolidated Edison's service area (primarily New York City) is expected to lag growth on Long Island. Consolidated Edison projected that annual requirements will grow by 1.5% per year over the forecast period, or by 45 BCF. Peak demand is projected to increase by .9% per year, or by 89,000 dth/day over the forecast period. Finally, winter season demand is expected to increase by 1.3% per year.

Exhibits III-1 and III-2 present the projected annual and peak day gas requirements for the New York City and Long Island markets.

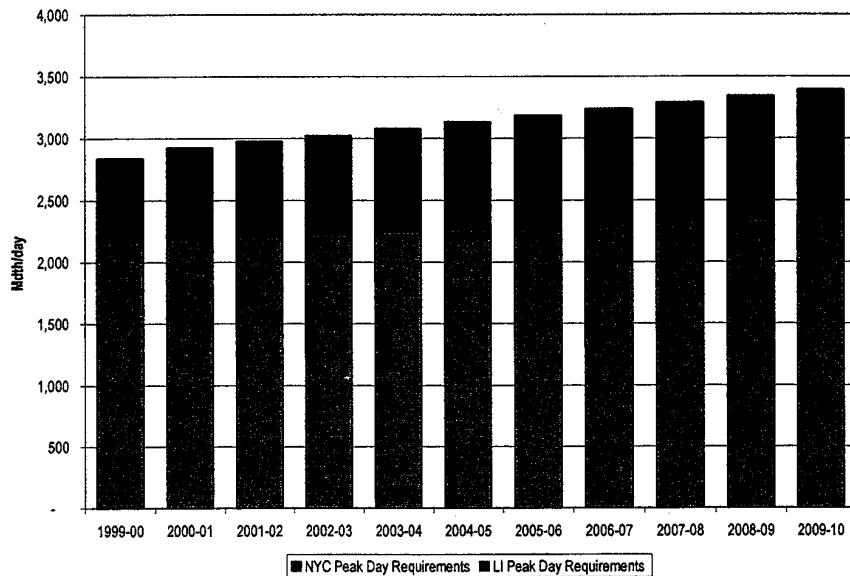
Exhibit III-1 Annual Throughput - New York City and Long Island



As illustrated, annual throughput in the target market is projected to increase by nearly 64 Bcf between 1999/00 to 2004/05 and 62.5 Bcf between 2004/05 to 2009/10. From

a peak day perspective, peak day requirements are projected to increase by 296,000 dth/day between 1999/00 to 2004/05 and 261,000 dth/day between 2004/05 and 2009/10. Winter season requirements are projected to increase by 42.1 BCF between 1999/00 and 2004/05, and an additional 40.5 BCF between 2004/05 and 2009/10.

Exhibit III-2 Peak Day Requirements - New York City and Long Island



III.2.b. Connecticut

All three Connecticut LDCs submitted Long Range Resource plans to the Connecticut Department of Public Utility Control in the 3rd Quarter of the year 2000, providing a ten-year forecast of resource requirements. The plans describe the Companies' demand forecasting procedures and integrated planning process. The Companies forecast annual and design day requirements and provide the supply resources available to meet projected loads.

Exhibits III-3 and III-4 provide aggregate forecasts for the combined LDCs in Connecticut for annual throughput and design (peak) day sendout, respectively. The results illustrate that over the ten-year forecast period, annual throughput is projected to increase at an average annual rate of 0.63% for the state overall. At the same time, design day demand is projected to increase at an average annual rate of 1.29% per year. Over the forecast period, peak day demand is projected to increase by 92,367 dth/day as is shown by Exhibit III-4.

For the Connecticut LDCs, all companies project that peak day requirements will increase at a much greater level than annual requirements. For example, Southern Connecticut Gas Company projects that total throughput will increase by 0.94% annually over the forecast period, while peak demand will grow by 1.28%. Both

Connecticut Natural Gas and Yankee Gas project growth rates in annual demand that are one-half the projected growth in design day demand. For Connecticut Natural Gas Company annual growth is projected to average 0.47% per year compared to 1.11% for design day demand. For Yankee, annual requirements are projected to increase by 0.5% per year while design day demand is projected to increase by 1.03%.

Exhibit III-3 Connecticut Annual Throughput

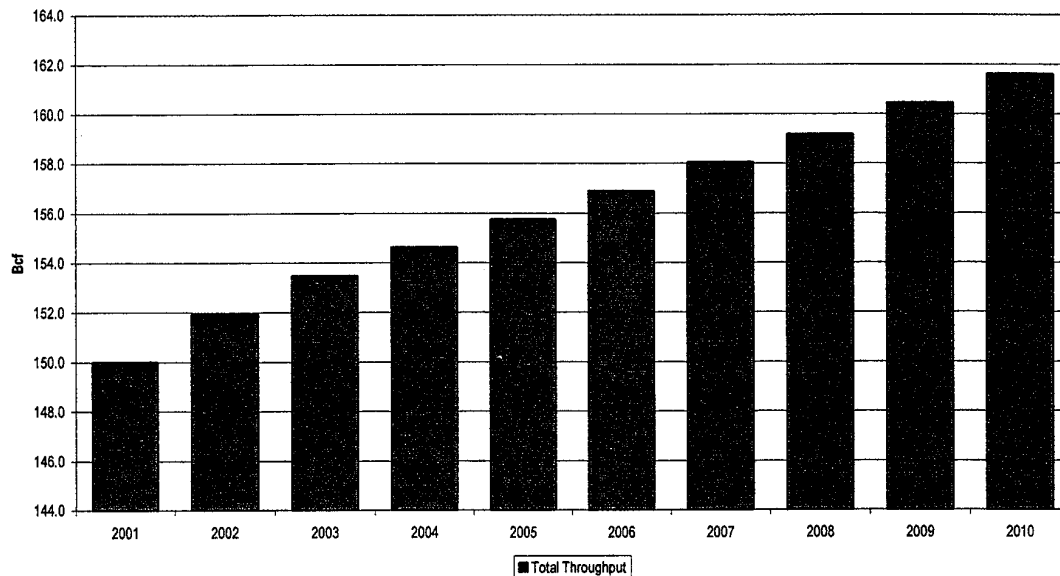
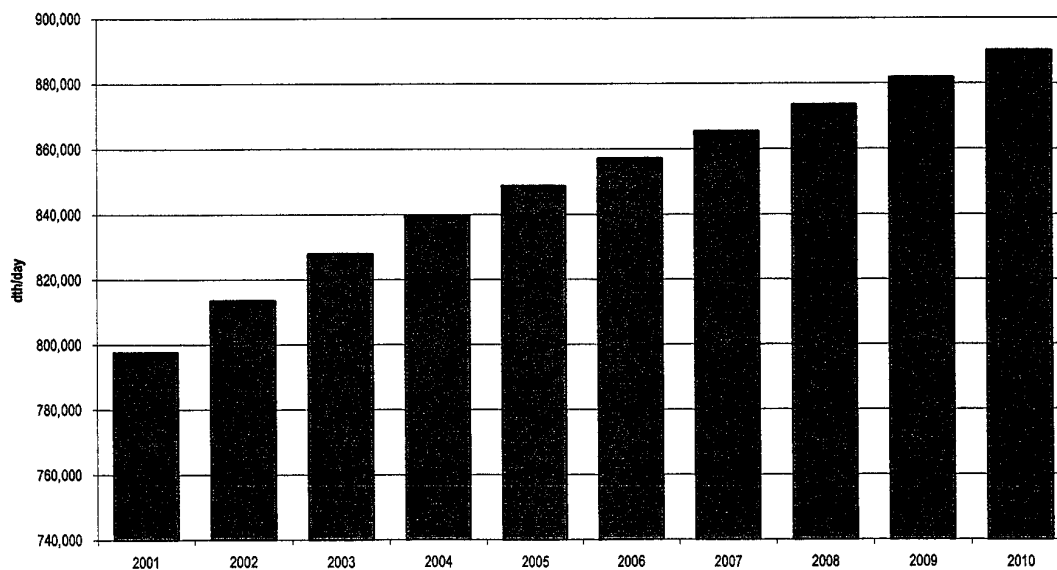


Exhibit III-4 Connecticut Design Day Sendout



Winter season requirements are projected to grow at an average annual rate of 0.8% per year, in excess of annual requirements.

There is considerable uncertainty as to how much of the new LDC loads will be served as sales customers or as transportation customers. Given this level of uncertainty, the LDCs may not be likely to firmly commit to new supply and transportation projects. The LDCs have stated that it is their intention to retain sufficient capacity to serve the needs of their customers. The construction of the Islander East project will add pipeline capacity infrastructure and increased deliverability, which will enhance natural gas reliability in the Connecticut market. Islander East will provide improved flexibility, diversity and optionality to Connecticut LDCs, and will result in increased pressure and deliverability particularly in the New Haven area.

IV. Electric Power Market Assessment

IV.1. New York Market Overview

As in other regions of the US, the power market is expected to be the largest growth market for natural gas in New York, with the need for new capacity and transmission constraints creating a robust market for gas-fired generation located within the target markets. However, the success of these projects will ultimately be based on the availability of natural gas supply and pipeline transportation to meet these requirements. The amount of natural gas required in this sector of the market can be estimated as a derived demand, based on the expected level of generation output from new and existing generation units.

The New York electric market is a large standalone energy market with unique characteristics that distinguish it from neighboring markets. In particular, the New York market is a bifurcated market, with major differences in resource mix, pricing and transmission access between eastern and western New York. New York has a population of over 18 million people, with approximately 7 million retail electricity customers. The market overall is a summer peaking system, with the majority of utilities classified as summer peaking utilities. Annual electricity requirements in New York totaled 156,029 GWh in 1999, while system peak load reached 30,311 MW.

The power market in New York has experienced much faster load growth than originally forecast. This has been due to the growth in the high technology sector and the information based economy, which has flourished in downstate New York. These users of electricity require high reliability with power quality issues of major concern.

Historically, the New York Power Pool (NYPP) was responsible for coordinating the development and operation of the electric production and transmission facilities of its member companies. The objectives of NYPP were to ensure optimal reliability of service and enhance the efficiency of operation from the interconnected systems of its members. NYPP dispatched power throughout New York on a single-system basis, optimizing economic dispatch, while meeting the prescribed reliability criteria.

As part of the restructuring process in New York, the member systems of the NYPP (investors-owned utilities, New York Power Authority (NYPA) and Long Island Power Authority (LIPA)) established the New York Independent System Operator (NYISO). Under this structure, NYPP was dissolved and many of the same functions have been assumed by the NYISO. The restructuring of the wholesale market involved the establishment of the ISO, replacement of the existing power supply markets with market-based spot markets, and establishment of a regional transmission tariff. The ISO assumed control of the New York electric power grid in November of 1999. The NYISO administers the State's wholesale electricity markets, maintains the reliability of the bulk power system and operates the State's high voltage transmission network. The ISO operates both day-ahead and real-time spot markets, and an energy market that relies on a locational-based, marginal pricing system for managing congestion.

As noted, the New York market contains many unique characteristics that define the market and underlie any analysis of the power market relative to its demand for natural gas. New York is classified as a net importer of power, relying on its interconnections with PJM, Ontario and Hydro-Quebec for power imports. In 1999, New York imported about 3% of its total energy requirements. This amount is expected to increase in the near term. The reliance on outside sources of power has raised reliability concerns in New York, since these purchases are now required to maintain the reliability standard set by the NYISO. As noted, the New York wholesale market operates as two separate markets, with different resource mix, pricing and power supply access. The wholesale market is distinguished by intra-regional transmission system bottlenecks that separate western New York from eastern New York markets. These transmission bottlenecks can create separate, localized market areas within a larger region, which can limit power flows and result in higher prices and limited power access.

In a recent study prepared by the Federal Energy Regulatory Commission (FERC) entitled, **"Investigation of Bulk Power Markets: Northeast Region, November 2000"**, the FERC noted that the existence of a significant west-to-east constraint divides New York State into two separate markets. The study further noted that congestion is also a problem for flows from north to south. Furthermore, in addition to the heavily congested interface, NYISO has localized transmission constraints into New York City and Long Island, the target markets for this analysis. While the implications of these transmission constraints will be discussed in more detail later, the upshot is that assessment of more localized markets is required for determining the amount and availability of gas infrastructure necessary to support power market requirements.

Other market characteristics are also important to consider and will be discussed in more detail in this section. As previously noted, New York overall has a balanced generation mix. However, on a regional basis this is not the case since most of the coal-fired generation is located in the western part of the state, while the majority of gas and oil-fired generation is located in the southeastern region. This contributes to a regional disparity in pricing, with western New York prices generally lower and less volatile than eastern New York.

In addition, the demand/supply balance has tightened considerably over the past few years in New York. The large generation surpluses expected only a few years ago have been whittled down and several areas of New York (notably the City and Long Island) will need capacity in the very near term. According to a recent report by the NYISO (**Power Alert: New York's Energy Crossroads, March 2001**) over the past five years, while statewide demand for electricity has increased by 2,700 MW, generating capacity additions totaled only 1,060 MW. As a result of transmission constraints and ISO requirements, the generation required to serve load in these regions will likely need to be produced by plants located in the market area. These plants will need to be approved and constructed in an expedited manner to meet demand. A large number of merchant power projects are being proposed for these markets, but will require gas supply and transportation capacity to meet fuel requirements.

Due to the energy crisis in California, attributed in large part to the shortage of electric power supply, New York City and Long Island markets have received considerable attention regarding the adequacy of generating capacity. While it is believed that New York City and Long Island will have adequate capacity to meet demand this summer, recent evidence has shown that electrical demand is increasing at significant levels. For example, summer peak demand in 1999 for LIPA was 8% higher than the previous year's summer peak, increasing by 382 MW. On average, electricity demand has been growing at an average annual rate of 3.5% on Long Island. According to Richard Kessel, Chairman of LIPA, demand during extreme heat conditions could exceed 5,000 MW this summer. Mr. Kessel also noted that LIPA could run short of capacity to meet demand in 2002 without conservation and new resources, with the situation becoming even more precarious during the 2003-2005 timeframe.

This section of the report will therefore provide a detailed assessment of the power market in New York with a focus on southeastern New York (i.e. New York City and Long Island). Both a qualitative and quantitative assessment is provided which ultimately projects the amount of natural gas supply and transportation capacity required based on the amount of new generation required in these markets and the use of gas to meet unit output.

IV.2. Demand/Supply Balance

The New York ISO and others have completed various studies, which illustrate the projected demand/supply balance for the state overall, and for regions or utilities within the state. The NYISO produces an annual forecast of peak demand requirements and generation resources (as NYPP previously produced). The report presents the NYISO and Transmission Owner's forecast of peak load, energy requirements, demand-side management, existing resources and planned changes, existing and proposed transmission, and normal power transfer limits. In the latest forecast entitled "**2000 Load and Capacity Data**" (July 1, 2000), the ISO projects that peak demand in New York state will increase at an average annual rate of 0.8% between 2000 to 2015. The same forecast projects that peak load for LIPA will grow at a rate of 1.4% per year and the peak load in ConEd's service area will grow at 0.7% per year, illustrating a disparity in load growth by region. The projected load growth is much lower than actual levels experienced in the 1990s. For example, between 1990-1999, summer peak load grew at an average annual rate of 2.17% for the state overall. For Long Island, load growth was even stronger, averaging 2.55% per year. The growth in ConEd's service area lagged the state overall at 1.96% per year.

The NYISO report entitled "**Power Alert: New York's Energy Crossroads**", was designed to examine the consequences on reliability, price, and environmental emissions associated with power plant construction scenarios. This report contains a substantially higher forecast of peak demand growth (i.e. 1.2% to 1.4% annually) than the NYISO's 2000 Load and Capacity Data Report. For both reports, the demand forecast underlies the conclusions derived from both assessments.

In addition to meeting demand, those serving load must also maintain a reserve margin to ensure reliability if a unit is out for maintenance or is forced out of service. The New York State Reliability Council (NYSRC), which has the responsibility for determining installed capacity requirements consistent with the Northeast Power Coordinating Council (NPCC) reliability criteria, has established a reserve margin of 18%. The Power Alert study noted that there was sufficient capacity within the New York control area plus net purchases with neighboring areas to meet the 18% reserve requirement in the year 2000. However, beyond 2000 there is a projected deficiency at the 18% reserve target. The NYISO noted that while the 18% reserve margin is sufficient for reliability purposes, the 18% installed capacity reserve does not ensure the robust competition needed for a healthy deregulated market for electricity. Furthermore, the reserve margin does not reflect the increased reliability requirements of the information economy. Thus, the 18% reserve margin serves only as the minimum required for reliability. Additional capacity beyond the minimum level is needed to stimulate competition.

The reliability criteria established by the NYISO contains certain nuances that influence the need for electric generating capacity within each region of the state. As a starting point, the NYISO assigns a proportion of the installed capacity requirement to each load serving entity (LSE) within the New York Control Area. LSEs within the Control Area may meet their installed capacity requirements through procurement of qualified capacity from resources within the control Area or from resources located in neighboring control areas directly interconnected to the New York Control Area. As specified by NYISO, resources located within PJM and Hydro-Quebec control areas may qualify as installed capacity suppliers to NYISO, but resources in the Ontario IMO and ISO-NE do not meet the NYISO's requirement relating to the recall of installed capacity providers. Therefore, resources located within these control areas do not qualify as installed capacity suppliers to the NYISO. As noted by the NYISO, since 1999 New York State has been unable to cover its reserve requirements from in-state sources, thereby relying on out-of-state resources to meet reliability requirements. The construction of additional generating capacity in New York will reduce the state's reliance on power supplies imported from other regions.

New York City and Long Island must meet certain reliability requirements, in addition to the same 18% reserve margin. For example, it is required that installed in-city generating capacity must be equal to at least 80% of projected peak demand in the City. For Long Island, the requirement is even more stringent. Installed generating capacity on Long Island must equal at least 98% of peak demand. This means that the load-serving entities must procure a percentage of their capacity requirements from resources located within the locality. The reliability requirements for these load pockets are driven by limitations in importing additional power over existing transmission lines within New York. These requirements will be addressed in our analysis of capacity needs later in this section.

Exhibit IV-1 New York Control Area Demand/Supply Balance

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Peak Load (adjusted for DSM)	30,311	30,200	30,460	30,790	31,070	31,300	31,510	31,740	31,990	32,250	32,480	32,720
Reserve Requirements	5,456	5,436	5,483	5,542	5,593	5,634	5,672	5,713	5,758	5,805	5,846	5,890
Total Requirements	35,767	35,636	35,943	36,332	36,663	36,934	37,182	37,453	37,748	38,055	38,326	38,610
Supply												
Steam Turbine (oil)		1,945	1,945	1,945	1,945	1,945	1,945	1,945	1,945	1,945	1,945	1,945
Steam Turbine (oil and gas)		9,969	10,139	10,139	10,139	10,139	10,139	10,139	10,139	10,139	10,139	10,139
Steam Turbine (gas)		226	226	226	226	226	226	226	226	226	226	226
Steam Turbine (coal)		3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968
Steam Turbine (wood)		38	38	38	38	38	38	38	38	38	38	38
Steam Turbine (Refuse)		262	262	262	262	262	262	262	262	262	262	262
Steam (PWR Nuclear)		2,409	2,409	2,409	2,409	2,409	2,409	2,409	2,409	2,409	2,409	2,409
Steam (BWR Nuclear)		2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588
Pumped Storage Hydro		1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040
Internal Combustion		72	72	72	72	72	72	72	72	72	72	72
Conventional Hydro		4,299	4,299	4,299	4,299	4,299	4,299	4,299	4,299	4,299	4,299	4,299
Combined Cycle		4,836	4,836	4,836	4,836	4,836	4,836	4,836	4,836	4,836	4,836	4,836
Jet Engine (oil)		506	506	506	506	506	506	506	506	506	506	506
Jet Engine (oil and gas)		164	164	164	164	164	164	164	164	164	164	164
Combustion Turbine (oil)		1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337
Combustion Turbine (oil & gas)		1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402	1,402
Combustion Turbine (gas)		34	154	154	154	154	154	154	154	154	154	154
Wind		0	0	0	0	0	0	0	0	0	0	0
Other		1	1	1	1	1	1	1	1	1	1	1
Interruptible Load SCR		140	140	140	140	140	140	140	140	140	140	140
Distributed Generation SCR		8	33	33	33	33	33	33	33	33	33	33
Additions		0	0	0	0	0	0	0	0	0	0	0
Retirements		0	0	0	0	0	0	0	0	0	0	0
NYCA Capability		35,244	35,559	35,559	35,559	35,559	35,559	35,559	35,559	35,559	35,251	35,251
Purchases		1,185	545	545	505	105	105	105	105	0	0	0
Sales		-313	-313	-313	-314	-308	-308	-308	-308	-308	-308	-308
Total Capability		36,116	35,791	35,791	36,760	35,356	35,356	35,356	35,356	35,251	34,943	34,943
Total Requirements		480	-152	-541	-913	-1,578	-1,826	-2,097	-2,392	-2,804	-3,383	-3,667

Based on the projected peak demand for the New York Control Area of 0.8% annually, combined with the projections for generating capability (assuming no new merchant are included at this point), New York will need to add new capacity or contract purchases beginning this summer to ensure an 18% reserve margin. The need for new capacity continues to increase, reaching nearly 2,000 MW by 2005 and approximately 3,700 MW by 2010. Exhibit IV-1 provides the demand/supply balance for the New York Control Area based on the forecasts contained in the NYISO's 2000 Load and Capacity Data Report. Again, this assumes a peak demand growth rate of 0.8 % per year, which is considerably lower than the 2.17% growth rate experienced during the 1990s. According to the North American Electric Reliability Council (NERC) (**2001 Summer Assessment, May 2001**), the forecasted demand plus reserve requirements has been increased to 36,132 MW for the summer of 2001.

The March 2001 analysis prepared by the NYISO illustrates a greater need for new capacity in New York based on the higher projected peak demand growth. According to the NYISO, the state overall will require 785 MW in 2001, increasing to 2,852 MW by 2005. The study also concludes that the state needs to add 8,600 MW of new installed electric generating capacity by 2005 to ensure a reliable supply in the state and to achieve both economic and environmental savings. Construction of the 8,600 MW would result in wholesale prices which are 20-25% lower than a no new generation case and produce 28% less sulfur dioxide and 43% less nitrogen oxides emitted.

IV.2.a. Demand/Supply Balance in Southeastern New York Markets

The demand/supply situation in southeastern New York illustrates a delicate balance in the near term. While demand has been increasing at a more rapid rate than for the state overall, supply additions have not kept pace and opportunities to import power into the target market area are limited by transmission constraints. For example, a recent report by the Federal Energy Regulatory Commission entitled **Investigation of Bulk Power Markets: Northeast Region, November 1, 2000**, discusses the problems facing New York City and Long Island as a result of transmission constraints.

New York City's load, which can exceed 10,000 MW, is served by in-city generators and by power imported through transmission lines from the north (running along the Hudson River) and east (from New Jersey). Each of these sources is constrained, creating a load pocket in the City. In-City generation totals about 7,900 MW (summer capacity), all of it oil or natural gas fueled. Little if any of the proposed 4,700 MW of new generation in the city is expected to be operable even by summer 2002. The NYISO expects more of it to be online within "three or four years". Thus, the outlook for new supply within the city is poor.

Transmission of power into New York City is limited by the capacity of the existing lines. Several lines run north to the Dunwoodie and Sprain Brook substations in the Hudson River Valley. This capacity is about 4,175 MW. Lines from New Jersey (part of the PJM system) normally have about 1,000 MW capacity, but they were limited in summer 2000 to 550 MW because a large transformer failed and could not be replaced before summer.

Total transmission into the city is therefore 5,175 MW when fully functional....If demand in the city is 10,000 MW, there is insufficient installed capacity to meet the reliability requirements.

In its March 2001 report, the NYISO also addressed the severity of the potential reliability problem in southeastern New York:

The situation in New York City and on Long Island is even more critical because these areas are "load pockets." A load pocket is an area where the import capability of the transmission system, together with the local generating capacity, is insufficient to meet the electricity demand in all hours. The risk of not being able to supply the electricity demand in such areas is highest in the event of a generator or transmission outage. Import capability into New York City and Long Island has remained essentially fixed, while electricity demand in both locales has continued to escalate. Therefore, it is critical that new plants be located "in-city" and "on-island" to maintain reliability, enhance competition and support economic growth.

An analysis of the data included in the NYISO Load and Capacity Data Report support FERC's assessment. As illustrated in Exhibit IV-2, the demand/supply picture for New York City and Long Island is even more dramatic. For the New York City market, peak load plus reserve requirements totaled 11,771 MW while generation in New York City totaled 7,875 MW, for a gap between demand and supply of approximately 3,900 MW. The same picture emerges for Long Island. Peak demand plus reserves in 2000 was 5,206 MW, while capacity totaled 4,369 MW on Long Island, for a gap of 837 MW.

Exhibit IV-2 New York City & Long Island Demand/Supply Balance (2000)

	New York City	Long Island
Demand (MW)		
Peak Load (adjusted for DSM)	9,975	4,412
Reserve Requirements	1,796	794
Total Requirements	11,771	5,206
Supply (MW)		
Steam Turbine (oil)	0	381
Steam Turbine (oil & gas)	4,932	2,048
Steam Turbine (gas)	0	226
Steam Turbine (Refuse)	0	115
Internal Combustion	2	20
Combined Cycle	1,028	237
Jet Engine (oil)	0	506
Jet Engine (oil & gas)	0	164
Combustion Turbine (oil)	710	548
Combustion Turbine (oil & gas)	1,183	124
Combustion Turbine (gas)	20	0
Total Capability	7,875	4,369
Demand less Supply	-3,896	-837

Finally, influencing the need for new capacity is the ISO rules establishing locational capacity requirements for LSEs. Locational capacity requirements have been established for two sub regions in New York state: in-city (New York City) and Long Island. Other locational requirements may be adopted in the future. Of the total installed capacity required for In-City load, a minimum of 80% must be located in-city. Of the total installed capacity required for Long Island load, a minimum of 98% must be located on Long Island. An additional requirement for total NYPP capacity is that no more than 10% of load can be met from resources outside the state. These provisions encourage the development of new generation in the New York City and Long Island areas.

The recent NERC 2001 Summer Assessment reports that the forecasted peak load for this summer on Long Island is expected to be 4,733 MW. The locational capacity requirement of 98% of the demand level is 4,638 MW. The existing capacity is 4,507 MW, which means there is a 131 MW shortfall. Although planned capacity additions scheduled for service this summer allow Long Island to meet its reliability target, new generation will continuously be required since load has been growing at a robust rate.

This indicates that to meet requirements, these two regions will either require that new generation is constructed within the region or that additional electric transmission capacity is available to deliver power into each of the regions. The transmission option was dealt a significant blow with the recent rejection by the Connecticut Siting Council of a 300 MW Cable project proposed by TransEnergie between southern Connecticut and Long Island.

In the 2001 Summer Assessment, NERC reports that New York City's forecasted peak load for the summer of 2001 is 10,535 MW, which means that 8,428 MW of generation (80%) is required in the City to meet load. With existing capacity reported at 8,031 MW, a shortfall of nearly 400 MW results.

In its March 2001 study, the NYISO presents several perspectives regarding the amount of additional generating capacity required in New York City and Long Island markets. First, based on the ISO's view that New York needs to add 8,600 MW of capacity by 2005 for reliability, economic, and environmental reasons, under this case the ISO has identified a need for 2,800 MW of capacity for New York City and 1,800 MW for Long Island by 2005. Under an alternative case where new capacity is added to meet reliability criteria only, New York City will need 865 MW of capacity by 2005, while Long Island will need 386 MW.

Merrimack Energy's analysis of the demand/supply balance in New York City and Long Island is based on the load forecast and supply capability included in the 2000 Load and Capacity Data Report. This analysis treats each region as a separate market and is premised on developing a demand/supply balance for each region whereby adequate supply to meet peak demand plus reserves are located within the region. Since New York City and Long Island are vulnerable to power shortages if transmission is interrupted, having a large amount of local generation reduces this need. Based on this analysis, Merrimack has identified a gap between demand and supply of over 1,200 MW of additional capacity by 2005 and over 1,600 MW by 2010. This analysis assumes that all the generation needed to meet load in southeastern New York has to be located in this market. While there is opportunity to import power from outside the state or from other regions of New York to meet requirements, the percent of generation required to be located within the market is expected to increase over time.

For New York City, there is a gap between load and in-city resources of about 3,900 MW currently. This increases to 4,300 MW by 2005 and 4,600 MW by 2010. While the gap between demand and supply resources is greater for New York City, the availability of transmission capacity into New York City can serve a portion of these requirements, although the percentage of resources required in the market is likely to increase. This analysis of the New York City and Long Island markets is illustrated in Exhibits IV-3 and IV-4.

Exhibit IV-3 New York City Demand/Supply Balance

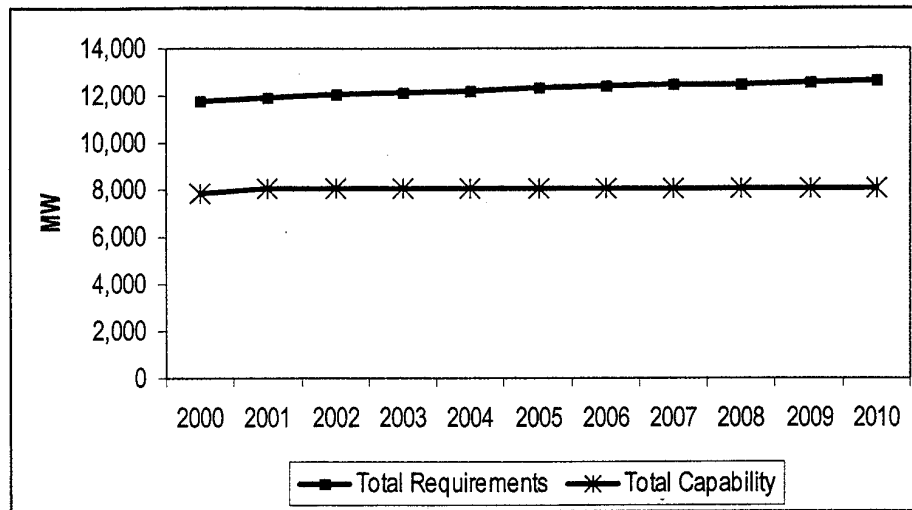
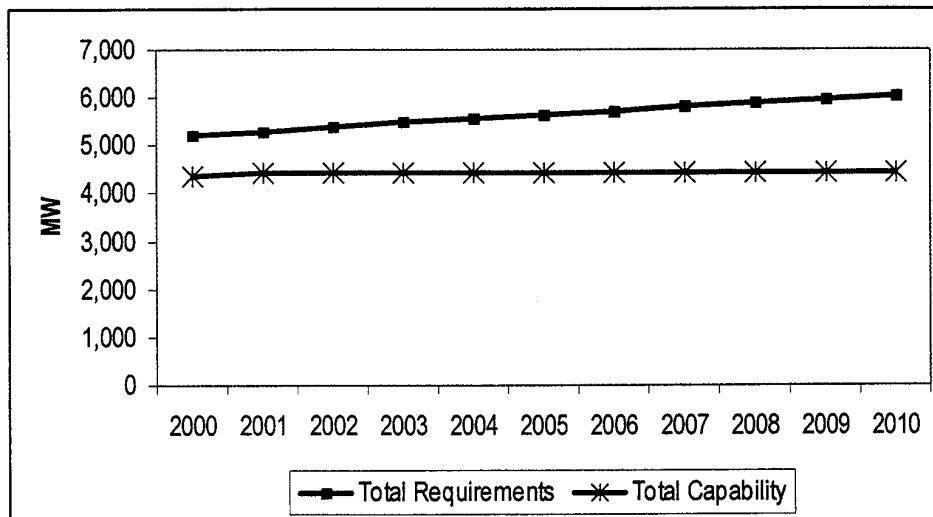


Exhibit IV-4 Long Island Demand Supply Balance



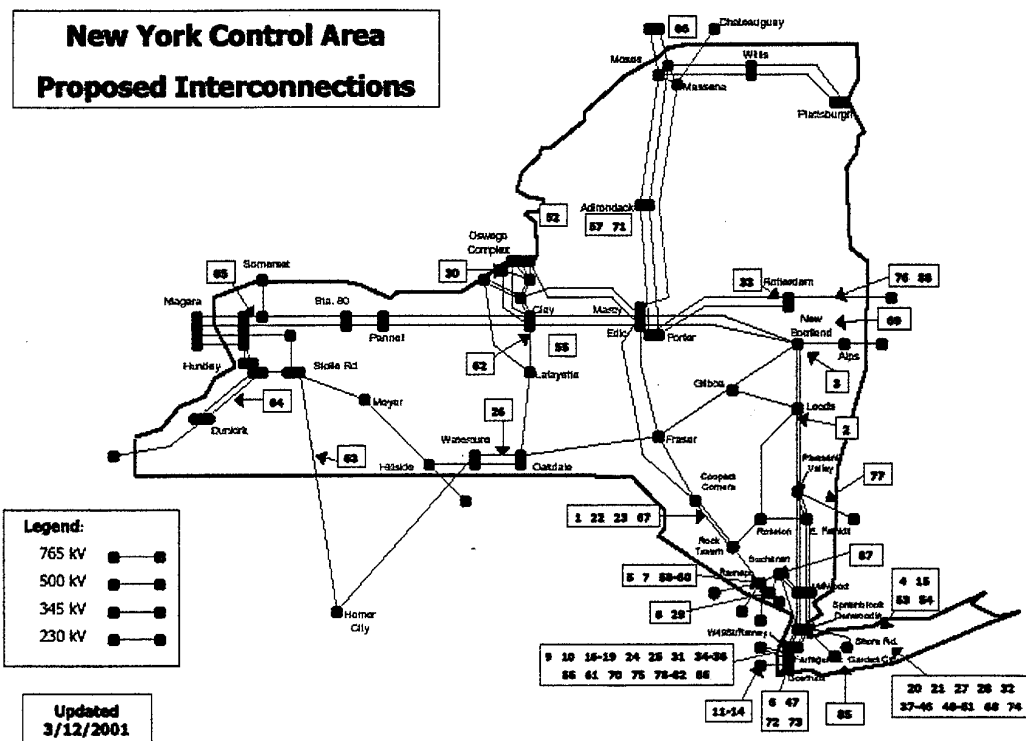
In conclusion, the results of this analysis clearly demonstrate the need to construct new electric generating capacity in New York City and on Long Island to meet existing requirements and future load growth and to ensure supply reliability in these markets. Since new generation is expected to be gas-fired, the amount of new capacity needed will influence the need for additional pipeline capacity to deliver the necessary fuel supply.

IV.3. Additional Generation/Merchant Plant Activity

A substantial amount of new generation has been proposed for New York, however few projects have received adequate environmental approvals. The vast majority of new generation proposed for the New York Control Area is merchant generation capacity. According to the NYISO, 170 MW of standby capacity will be added in New York City during 2001 via reactivation of steam turbine capacity. However, this generation is identified as back-up capacity only. Also, minor expansions at several KeySpan facilities on Long Island have been initiated to meet requirements. These expansions will add less than 100 MW. Approximately 120 MW of temporary capacity is proposed for Long Island via gas turbine generating barges and rerating of several gas turbines. The remaining units proposed are anticipated to be merchant plants.

The level of merchant plant activity has increased rapidly in New York over the past several years and new projects are continuing to be proposed. These new project proposals have been influenced by the recent increases in demand, which has led to a need for new capacity sooner than previously indicated, the restructuring of the wholesale market, and the high prices experienced in the market since its inception. For example, by the end of 1999, twenty-seven projects representing over 15,000 MW had either filed or expected to file for interconnection studies with the NYISO. Based on most recent data compiled by the NYISO, there are currently approximately eighty-six projects representing over 32,000 MW identified by the NYISO. Exhibit IV-5 from the NYISO web site, illustrates the locations of projects within the New York Control Area. A complete list of the projects is included in Appendix B.

Exhibit IV-5 New York Control Area Proposed Projects



There are a number of interesting observations that can be drawn from review of this information about merchant generation that will impact the timing and viability of these projects:

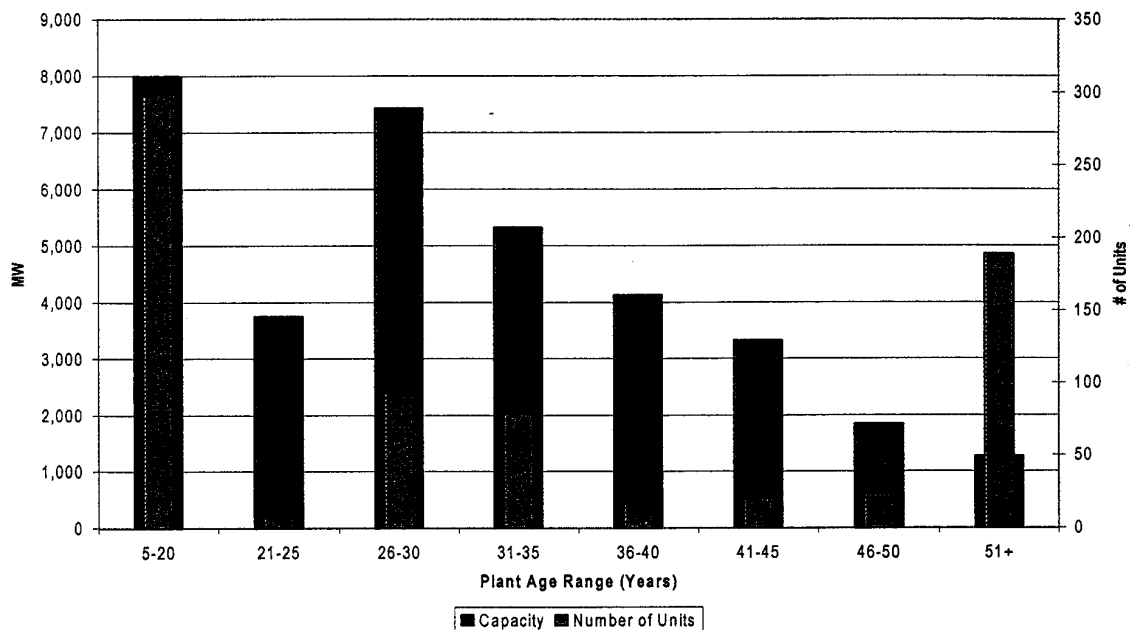
1. Only one of the merchant generating projects, the 1,080 MW Athens Generation project, has received Article X approval. This is the only project which appears likely to be in-service by 2002
2. Two other projects proposed for operation by 2002 are electric transmission projects. However, the Connecticut Siting Council rejected the TransEnergy HVDC Cable project rated at 300 MW in April 2001. This project was designed to provide a 300 MW interconnection between southern Connecticut and Long Island. Failure of this project will require that additional generation will have to be built on Long Island.
3. Virtually all the power generation projects are gas-fired units.
4. A large number of the projects are proposed for the New York City and Long Island areas. For example, 30 generating projects totaling about 10,600 MW are proposed for New York City and 20 generating projects totaling nearly 5,400 MW

are proposed for Long Island. In addition, four transmission projects from Connecticut to Long Island have been proposed with an estimated transfer capability of over 1,500 MW.

Delays attributed to the Article X siting process in New York could ultimately influence the timing and success of these projects.

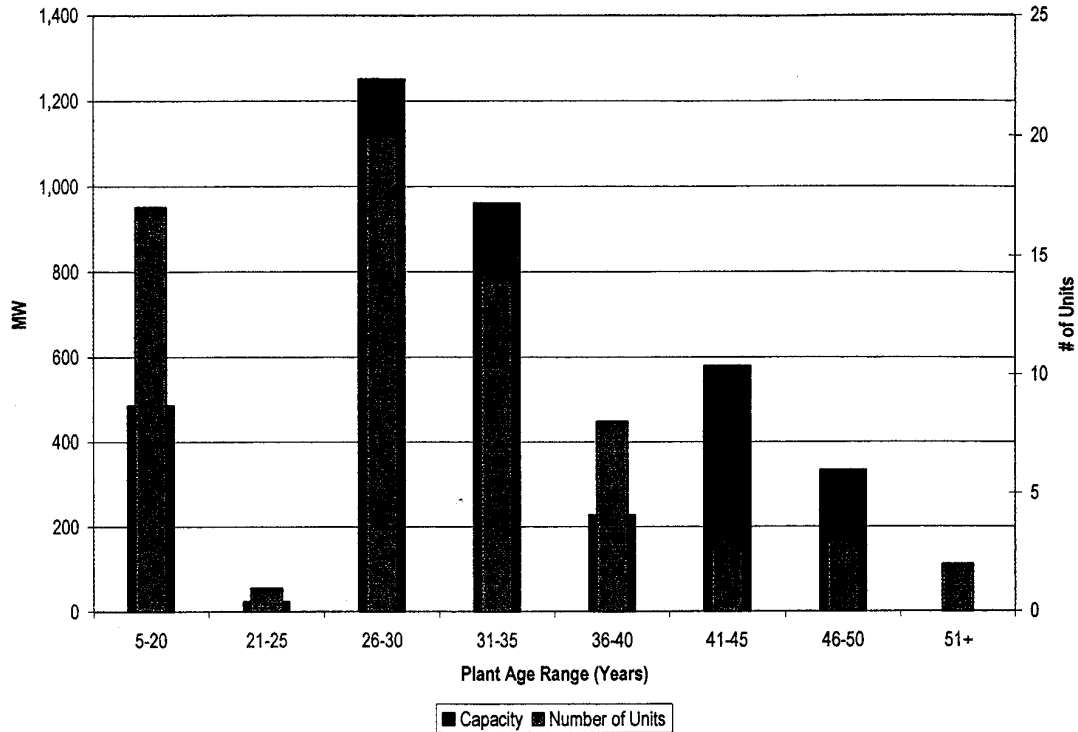
Also influencing the need for new generating capacity is the age distribution of existing facilities. Over 75% of the generating capacity in New York is in excess of 25 years of age. Exhibit IV-6 provides a breakdown of the average age of generating units in New York by capacity type.

Exhibit IV-6 Age Distribution of New York Control Area Generating Units



In the Long Island market, the age distribution is even more heavily weighted towards older, less efficient units with approximately 90% of the units more than 25 years old, which is demonstrated in Exhibit IV-7.

Exhibit IV-7 Age Distribution of Long Island Generating Units



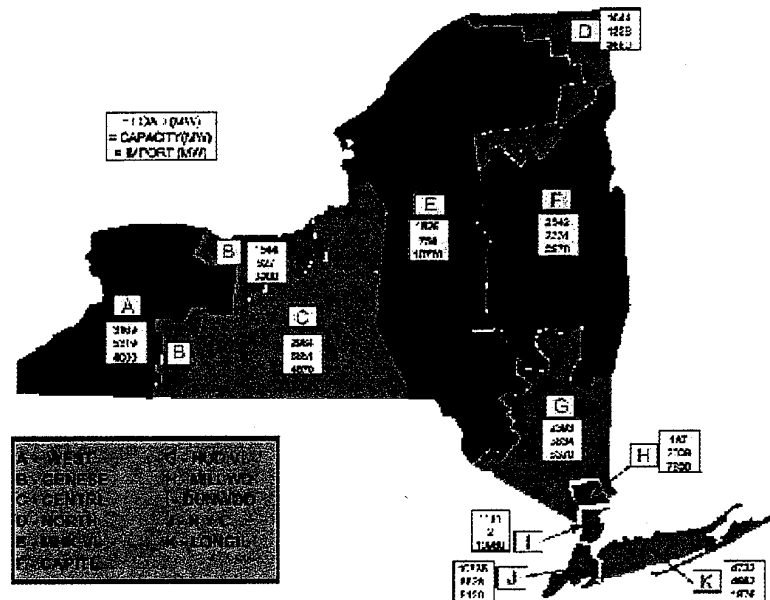
IV.4. Transmission System/Infrastructure

Several transmission projects have been proposed to meet load on Long Island. In addition, transmission of power into the market areas of New York and Long Island from other regions in New York could be a source of power to meet load. However, recent regulatory decisions and actions illustrate the difficulty in building any new transmission projects. This section of the report will assess the transmission infrastructure in New York and explore the option of relying on power from other regions of New York or from neighboring utility systems to meet load growth in the target markets.

The New York transmission system connects bulk power generators and loads throughout the state of New York. The bulk transmission system in New York contains over 10,000 miles of transmission lines, and consists primarily of 115-kv, 138-kv, 230-kv, and 345-kv facilities. Nearly one-half of these facilities are in the service area of Niagara Mohawk. In terms of facility type, the transmission facilities in the northern part of the state are generally longer in length and fewer in number than the downstate area. This reflects the prevalence of lower cost generation in upstate New York and the higher load concentration (and less generation) in the downstate markets.

The New York market has been divided into several areas to reflect transmission constraints and load pockets or zones with the state. For example, Exhibit IV-8 presents a map of the New York system based on eleven load pockets. Load Pockets J and K largely reflect the target market for this assessment. The NYISO 2000 Load and Capacity Data Report provides a listing of the generation in each load pocket, which allows for a comparison between the load and generation in each zone.

Exhibit IV-8 NYISO New York Control Area Map



The NYISO can also be segregated based on transmission capacity limitations. The NYISO can therefore be divided into the Western and Eastern regions, with Zones A,B,C,D and E in the Western Region and F,G,H,I,J and K in the Eastern Region. The Western Region generates a disproportionate share of generation relative to its load and must therefore deliver the power to other regions within New York. For example, it has been estimated that the Western region generates 40% of all energy within NYISO, but is responsible for only 34% of the total peak demand. Thus, generators in the Western Region must serve a portion of the Eastern Region's load via the bulk transmission system.

Internal transmission constraints have been a major issue within New York. The Total-East interface, which divides central and western New York from eastern and southeastern New York, represents the primary constraint for energy transfer from the western region to the eastern region. This interface has a capacity of approximately 5,300 MW and congestion occurs over 75% of the time. Exhibit IV-9 illustrates the transfer limits between regions within New York.

Exhibit IV-9 Transmission System Transfer Capability

2000 Load & Capacity Report						
INTERNAL INTERFACES	Capacity	Limiting Element	Limit	Rating	Contingency	Study
Dysinger-East	3226 Mw	Rochester 345kV Bus	@ Post-low Voltage Limit	328 kV for	STUCK BREAKER: Loss of Kinigh-Rochester 345 kV (SR-1) & Rochester-Parnell Road 345 kV (RP-1)	(5)
West-Central	2226 Mw	Rochester 345kV Bus	@ Post-low Voltage Limit	328 kV for	STUCK BREAKER: Loss of Kinigh-Rochester 345 kV (SR-1) & Rochester-Parnell Road 345 kV (RP-1)	(5)
Volney-East	4560 Mw	Oakdale 345kV Bus	@ Post-low Voltage Limit	320 kV for	Loss of TOWER: Edin-Fraser 345 kV & Marcy-Coopers Corners 345 kV (Marcy-Exeter after 2002)	(1)
Moses-South (South)	2650 Mw	Marcy-Edin 345 kV	@ LTE Rating	1792 Mw for	Loss of TOWER: Marcy-New Scotland 345 kV & Adirondack-Porter 230 kV	(1)
Moses-South (North)	1900 Mw	Chateauguy HVDC terminals	@ Normal Rating	1000 Mw	N/A	(2)
Total-East	6500 Mw	New Scotland 345 kV Bus	@ Post-low Voltage Limit	328 kV for	Loss of TOWER: Fraser-Coopers Corners 345 kV & Marcy-Coopers Corners 345 kV (Marcy-Exeter after 2002)	(1)
UPNY-SENY	4980 Mw	Leeds-Pleasant Valley 345 kV (B1)	@ LTE Rating	1638 Mw for	Loss of Leeds-Pleasant Valley 345 kV (B2)	(4)
UPNY-Con Ed	5680 Mw	Rock Tavern-Ramapo 345 kV	@ LTE Rating	1890 Mw for	Loss of Roseton-Fishkill 345 kV & East Fishkill 345/115 kV	(1)
Millwood-South	8000 Mw	Sprainbrook-Dunwoodie 345 kV	@ LTE Rating	2708 Mw for	Loss of TOWER: 2 x Fishkill-Wood St-Pleasantville 345 kV, Wood St 345/115 kV & Pleasantville 345/115 kV	(1)
Dunwoodie-South	8080 Mw	Sprainbrook-West 49th St	@ Normal Rating	774 Mw	N/A	(1)
Con Ed-LIPA	1080 Mw	Dunwoodie-Shore Road 345 kV	@ Normal Rating	687 Mw	N/A	(1)
NEPOOL INTERFACES	Capacity	Limiting Element	Limit	Rating	Contingency	Study
OH-NYPP	2226 Mw	Rochester-Parnell Rd 345 kV (RP-1)	@ LTE Rating	1601 Mw for	STUCK BREAKER: Loss of Rochester-Parnell Rd 345 kV (RP-2) & Rochester 345/115 kV transformer	(5)
NYPP-OH	1560 Mw	Beck - Hannon 220 kV (J24)	@ LTE Rating	623 Mw for	Loss of TOWER: Beck - Noble - Middleport 220 kV (J25) & Beck-Hannon-Middleport 220 kV (J26)	(5)
PJM-NYPP	3180 Mw	Oakdale - Watercure 230 kV	@ LTE Rating	400 Mw for	Loss of Oakdale - Watercure 345 kV	(5)
NYPP-PJM	326 Mw	Homer City - 345 / 230 kV bank #1	@ Emergency Rating	733 Mw for	Loss of Homer City - 345 / 230 kV bank #2	(5)
NEPOOL-NYPP	1600 Mw	Derby Junction-Steverson 115 kV	@ STE Rating	193 Mw for	STUCK BREAKER: Loss of Southington-Frostbridge 345 kV & Haddam-Southington 345 kV	(5)
NYPP-NEPOOL	1426 Mw	Nonewick-Northport 138 kV	@ LTE Rating	315 Mw for	STUCK BREAKER: Loss of Long Mountain-Plumtree 345 kV, Long Mountain-Frostbridge 345 kV, Long Mountain-Pleasant Valley 345 kV, & Frostbridge 345/115 kV Transformer	(5)
HO-NYPP	2470 Mw	Chateauguy - Massena 765 kV	@ Stability Limit (Coders report @ 100 Mw)	2370 Mw for	Loss of TOWER: both Moses-St. Lawrence 230 kV circuits	(3)
NYPP-HQ	1000 Mw	Chateauguy HVDC terminals	@ Normal Rating	1000 Mw	N/A	(2)

Notes: The above Transfer Capabilities apply to the New York State planning period of 1999 through 2018. The NYPP planning definition of the Dunwoodie-South interface includes the Y48 and Y60 cables into Long Island.

Study: (1) Review of the Reliability of the New York Power Pool Bulk Power Transmission System in the Year 2000 -- NYPP Triennial Transmission Review (September 1994)
 (2) Chateauguy Reverse Mode Stability Analysis -- Winter 1995/90 Revision (December 1998)
 (3) A Reevaluation of NYPP Stability Analysis Considering Impact from Hydro Quebec: Over the MSC-7040 Line at 2370 Mw (March 1993)
 (4) Total East Transmission Study Progress Report - Base Case Limits (February 1998)
 (5) New York Power Pool Summer 1999 Operating Study (April 1999)

The most notable constraint is the Central-East interface which bisects the market between Utica and Albany. According to FERC (Investigation of Bulk Power Markets: Northeast, November 2001), the Central-East interface (a set of transmission lines feeding power from north and west into the eastern part of the state) was at its capacity limit approximately 80% of the time in June of 2000. According to the FERC study the constraints at the Central-East interface have remained significant for the past two years and the interface is often heavily loaded with west-to-east flows. Central-East congestion can also limit imports from Hydro-Quebec into ISO New England (ISO-NE). Congestion is also a problem for flows from north to south. A consequence of these constraints is that all of the 10-minute reserves must be located in the eastern part of the state.

Localized transmission constraints into New York City and Long Island are also an issue and are related to contingency operating requirements and physical transmission limitations. As noted, the capacity requirements for these load centers are treated separately from the rest of the NYISO Control Area, reflecting the concentration of load in, and the limited ability to import power into, these areas. Constraints could lead to pricing differentials between western and eastern New York of \$4-\$5/MWH or more on average. Review of data for 2000 indicates that prices in the New York City and Long

Island zones were higher than the average prices in the system. Prices in western New York have recently been propped up by nuclear outages in Ontario, causing exports of power from New York to Ontario. As a result, consumers in New York City and Long Island have had to rely heavily on in-city generation rather than more economic resources located in western New York or other states. According to the FERC study, "New York City and Long Island have limited capacity to import power, so they are vulnerable to blackouts if transmission is interrupted".

IV.5. The Market For Power and Gas Transportation in the Target Markets

To assess the need for natural gas supply and transportation capacity in the target markets, it is necessary to first assess the need for new generating capacity in the target market and then determine the associated fuel requirements. To conduct such an assessment, a generation expansion and production cost simulation of the target market has been undertaken, given the transmission constraints previously mentioned, and the projected need for new generation capacity in the target market. Based on the fuel requirements of these new generators, Merrimack Energy then proceeded to estimate the amount of peak day pipeline capacity required to meet the projected output of these new merchant generators. This analysis also considers the expected operations of existing units, including displacement of gas in existing generating units, to arrive at a total peak day pipeline capacity requirement.

IV.6. Gas Transportation System Adequacy

An area of concern associated with potential development of new power generation projects in the Northeast is the adequacy of the gas transportation system to support project development. ISO-NE recently completed a major study of the gas system to determine its capability for supporting additional power generation. The study concluded that additional pipeline capacity was required to support needed gas-fired electric generation.

Likewise, the NYISO has identified the need for a similar study to determine the need for additional natural gas pipeline capacity to support the additional generation of electricity, which is extremely important and urgently needed. The NYISO, in fact, recognizes that additional gas pipeline capacity is needed to provide fuel supply to support power generation.

The March NYISO report stated with regard to the adequacy of pipeline capacity in the target markets:

At the present time, during the winter, in the New York City and Long Island areas most natural gas is used for heating, and there is little, if any, additional pipeline capacity available to deliver gas to electric generating stations. During the coldest winter days, the new plants will have to be able to use an alternate fuel, usually oil.

Thus, new power generation plants are generally required to be located in the market area. However, there are a number of constraints that may inhibit development of these projects. First, the adequacy of pipeline capacity may be an issue affecting development of new electric generation capacity. Second, the Title X process is sure to delay the in-service date of new units in the New York City and Long Island areas. Third, the difficulties associated with development of new electric transmission facilities (e.g. TransEnergie Long Island Cable Project) will mean that additional generation located with access to the existing transmission grid will be required. All these factors point to a need for the Islander East Project as a mechanism for delivering high-pressure gas supplies to the target markets to fuel the required generation

IV.7. Gas Transportation Needed to Support Generation

This section of the report has identified and described several cases assessing the demand/supply balance in the target market. These include:

1. Add generation to meet reliability criteria only. This includes meeting the 18% reserve margin and the in-region generation requirements associated with a percentage of load.
2. Add generation to create a more competitive wholesale market.
3. Balance demand and supply for each region under the premise that all generation to meet load is included in the localized region.
4. Projected levels of generation based on the market simulation analysis.

The first two cases reflect the assessment of the New York market contained in the March 2001 NYISO report. The third case uses demand and supply data for each region based on NYISO load and capacity data. The fourth case is based on market simulation modeling for the target markets.

For each case, the need for new electric generation and the associated pipeline capacity required to provide gas supply to meet project output is determined. The level of generation required under each case and the associated pipeline capacity needed is provided in Exhibit IV-10.

Exhibit IV-10 Cumulative Generation & Related Pipeline Capacity Requirements - Long Island

	Case 1	Case 2	Case 3	Case 4	Case 1	Case 2	Case 3	Case 4
Year	Generation to Meet Reliability Only (MW)	Generation For a Competitive Wholesale Market (MW)	In-Region Generation Balance (MW)	Generation Expansion Plan (MW)	Pipeline Capacity Dth/day	Pipeline Capacity Dth/day	Pipeline Capacity Dth/day	Pipeline Capacity Dth/day
2001	131	200	879	88	20,960	32,000	140,640	14,080
2002	202	200	975	418	32,320	32,000	156,000	66,880
2003	269	500	1,070	748	43,040	80,000	171,200	119,680
2004	330	1,300	1,151	748	52,800	208,000	184,160	119,680
2005	386	1,800	1,228	748	61,760	288,000	196,480	119,680
2006			1,308	748			209,280	119,680
2007			1,392	748			222,720	119,680
2008			1,479	998			236,640	159,680
2009			1,557	998			249,120	159,680
2010			1,621	998			259,360	159,680

The amount of electric generation capacity required for Long Island by 2005 ranges from 386 MW to 1,800 MW. Thus, it can be expected that from one to four average size projects (i.e. 500 MW) will be required on Long Island. Under the case whereby in-region needs are met totally by in-region generation, at least two projects would be needed by 2005. Based on these cases, the Long Island market will require from nearly 62,000 dth per day to 288,000 dth per day of pipeline capacity by 2005 to serve the electric load alone.

For the New York City market, the amount of new generation and associated pipeline capacity additions required is likely to be greater. Under the first two cases presented in the March 2001 NYISO report, New York City would need from 865 MW to 2,800 MW of generating capacity by 2005. This translates into a need for pipeline capacity of 138,400 dth per day under the low case to 448,000 dth per day under the high case. Certainly, in the case whereby all generation is located in-region the need for electric generation capacity and associated pipeline capacity increases dramatically to 4,300 MW and 687,000 dth per day respectively. While we do not expect that all capacity will need to be located in the City, it is important to note that the 80% minimum generation requirement is expected to increase into the future. The level of generation requirements and associated pipeline requirements for the New York City market are illustrated on Exhibit IV-11.

Exhibit IV-11 Cumulative Generation & Related Pipeline Capacity Requirements - New York City

	Case 1	Case 2	Case 3	Case 4	Case 1	Case 2	Case 3	Case 4
Year	Generation to Meet Reliability Only (MW)	Generation For a Competitive Wholesale Market (MW)	In-Region Generation Balance (MW)	Generation Expansion Plan (MW)	Pipeline Capacity Dth/day	Pipeline Capacity Dth/day	Pipeline Capacity Dth/day	Pipeline Capacity Dth/day
2001	397	300	3,855	750	63,520	48,000	616,800	120,000
2002	529	500	3,997	1,250	84,640	80,000	639,520	200,000
2003	649	1,800	4,115	1,500	103,840	288,000	658,400	240,000
2004	765	2,300	4,203	1,427	122,400	368,000	672,480	228,320
2005	865	2,800	4,292	2,542	138,400	448,000	686,720	406,720
2006			4,357	3,042			697,120	486,720
2007			4,422	3,042			707,520	483,720
2008			4,487	3,042			717,920	486,720
2009			4,552	3,042			728,320	486,720
2010			4,616	3,042			738,560	486,720